EXHIBIT
#21
DE 16-576

ENERGY FREEDOM COALITION OF AMERICA

DIRECT TESTIMONY OF

Patrick Bean

New Hampshire Public Utilities Commission

Docket No. DE 16-576

I. Introduction and Purpose of Testimony

Please state your name, business address, position and for whom you are filing testimony.

My name is Patrick Bean. I am a Deputy Director of Policy and Electricity Markets at SolarCity. My business address is 601 13th Street NW, Suite 900, Washington, DC 20005. I am filing testimony on behalf of the Energy Freedom Coalition of America (EFCA). SolarCity is a member of EFCA.

Please describe your position, experience and qualifications.

As Deputy Director at SolarCity, my responsibilities include providing quantitative analysis of electricity markets, rate designs and distributed energy resource (DER) policies across the nation, with a primary focus on States east of the Mississippi. I engage in utility regulatory proceedings including rate cases, grid modernization and distributed generation programs.

Prior to joining SolarCity, I was a Senior Research Associate at the King Abdullah Petroleum Studies and Research Center (KAPSARC) which is a multi-disciplinary international energy think tank in Riyadh, Saudi Arabia. My research included statistical and economic analysis of energy productivity and renewable energy policies. I also led the development KAPSARC's "Utilities of the Future" research program which seeks to create tools to simulate electricity systems with high levels of DERs, and to provide insights about new business and regulatory models given the rise of DERs.

I previously worked at Southern Company as a Strategic Generation Planner for three years. I developed a new generation planning method to manage market uncertainty and minimize regrets and led the company's quantitative environmental policy analysis. My work was used to determine which power plants to build, retire or upgrade, and the analysis was used in regulatory filings, including the integrated resource plan, rate cases, and generation certification filings.

I hold a Bachelor of Science degree in Environmental Science and Policy from Marist College, and a Master of Environmental Management in Energy and Environmental Resources from Duke University. My resume is attached as Exhibit EFCA-PB-1.

Have you previously testified before the New Hampshire Public Utilities Commission?

No I have not.

What is the purpose of your testimony?

EFCA's goal is to create a healthy and sustainable regulatory environment in New Hampshire whereby DERs can flourish and provide benefits to customers, utilities and the grid. This proceeding should lay the groundwork for creating such an environment and provide customers, regulators, utilities, DER providers and other stakeholders with a long-term vision for net metering, DERs and the electricity system. This can be accomplished by developing pilot studies for alternative net metering tariffs, creating programs to collect and disseminate data, reforming distribution system planning, adopting an automatic rate adjustment mechanism, and encouraging utility investments that integrate more DER.

My testimony addresses several topics that are relevant to the objectives set forth by New Hampshire House Bill 1116, including the consideration of new alternative tariffs and other regulatory mechanisms that can help ensure continued opportunities for customer-generators.

The topics include:

1. Recommendations for data collection and sharing requirements to enable more refined analysis of costs and benefits of DERs, and identification of DER opportunities.
2. Reforms to the distribution system planning process to evaluate non-wires alternatives.
3. Alternative rate and regulatory mechanisms for consideration.
4. Possible Pilot Projects

SolarCity published a white paper in February 2016, called "A Pathway to the Distributed Grid", relevant to the data sharing, cost-benefit analysis, and distribution planning topics discussed in this testimony. I have attached the white paper as Exhibit EFCA-PB-2.

In preparing your testimony, did you have the opportunity to review the testimony of The Alliance for Solar Choice's (TASC) witness, Thomas Beach?

Yes, I did.

Why was reviewing Mr. Beach's testimony important to your testimony?

Mr. Beach has extensive experience calculating the costs and benefits of distributed generation, and the findings of his analysis provide insights into whether changes to New Hampshire's net metering program are warranted.

Does Mr. Beach provide a reasonable analysis?

Yes. Mr. Beach calculates the costs and benefits of net metering in a manner that follows the developing consensus for best practices of such analysis. He evaluates NEM from a variety of perspectives using accepted methodologies including the participant cost test, rate impact measure, total resource cost test, and societal cost test. Further, he includes a comprehensive list of cost and benefit categories and provides reasonable analysis given the data available.

Are you submitting a cost-benefit analysis of distributed solar with your testimony?

No, I am not. Having reviewed Mr. Beach's analysis, I did not see the need to repeat the analysis.

Does net metering present an unjust and unreasonable cost-shift in New Hampshire?

No. As shown in Mr. Beach's benefit-cost analysis,[1] net metering provides net benefits to all of New Hampshire's electricity consumers. Moreover, the State's utilities have not provided sufficient evidence that a cost-shift exists, or if one does, that it is unjust and unreasonable. For example, Unitil estimated displaced revenues of $15,261 due to net metering in 2013.[2] Even this is likely an overestimation since it estimates generation from all installed solar capacity and multiplies the generation by the distribution tariff rate to determine the utility's displaced revenues. It is likely an overestimation of solar generation because all solar installations are assumed by Unitil to be south-facing, which is an orientation that maximizes generation, and operating at nearly 19% capacity factor.[3] Not all roofs are south-facing and some homes can experience shading throughout the day due to the positioning of trees or other structures. Moreover, Unitil does not consider degradation of solar panels which reduces the amount of generation over time,[4] and the company appears to be relying on typical metrological year (TMY) – 2 data, rather than the most recent TMY3 dataset which estimates lower solar generation for Concord, NH than TMY2.[5] These actions will cause an overestimation of solar generation.

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[1] Direct Testimony of R. Thomas Beach before the New Hampshire Public Utilities Commission. Case number: DE 16-576

[2] Unitil response to NHSEA 1-15.

[3] Unitil response to NHSEA 1-15 attachment 1.

[4] Research has shown annual degradation is likely around 0.5%/year. *See* Jordan, C.D., and Kurtz, S.R. 2012. *Photovoltaic Degradation Rates – An Analytical Review*. NREL. Available from: http://www.nrel.gov/docs/fy12osti/51664.pdf

[5] TMY2 data has 4% more solar output for Concord, NH than TMY3 as calculated from NREL's PVWatts tool. For more information about the TMY3 dataset, *see* Wilcox, S. and Marion, W. 2008. *Users Manual for TMY3 Data Sets*. NREL, available from: http://www.nrel.gov/docs/fy08osti/43156.pdf

Eversource estimates their lost distribution revenue due to net metering is some $560,000 per year.[6] Their estimate also assumes that all installations operate in the same fashion (15% capacity factor), and assumes that 50% of the solar production is consumed onsite and results in displaced sales. Again, these actions will cause an overestimation of solar generation.

Further, neither of these examples provided by utilities includes consideration of the benefits provided by net-metering. Unitil acknowledged that it has not conducted any studies or analyses addressing the actual or potential benefits of solar DG installation to the distribution system, nor does it believe that such benefits exist.[7] Without a benefit-cost analysis, it is impossible to conclude that an unjust and unreasonable cost-shift exists.

Why do benefits matter when determining whether there is an unjust and unreasonable cost-shift?

The nature of ratemaking based on the average ratepayer in a class means that intra-class cross-subsidization is inherent. For example, the residential rate class is comprised of many different types of dwellings that have different electricity patterns and different costs of service, such as different costs for urban and non-urban areas, yet all customers in the class pay the same rate. Recent research has found that utility regulatory commissions have routinely allowed cross-subsidization, particularly when it benefits the utility system.[8] If a cross-subsidy is identified and its benefits outweigh the costs, all electricity consumers are better off and the cross-subsidization is not unjust or unreasonable.

Should changes be made to net energy metering (NEM) programs in New Hampshire?

Net metering has been, and continues to be, a fair and efficient mechanism for encouraging the adoption of distributed solar in New Hampshire, and therefore should not be changed at this time. As shown by Mr. Beach,[9] NEM provides net benefits for all electricity consumers. Changes to NEM should not be considered until analysis shows the program does not provide substantial benefits. Further, the absence of relevant utility data in New Hampshire virtually eliminates the ability to make intelligent decisions about changing net metering.

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[6] Eversource response to NHSEA 1-15.
[7] Unitil response to Staff-UES-10
[8] Peskoe, A. 2016. *Unjust, Unreasonable, and Unduly Discriminatory: Electric Utility Rates and the Campaign Against Rooftop Solar.* Texas Journal of Oil, Gas, and Energy Law. Vol. 11:2. Pg. 108-109.
[9] Direct Testimony of R. Thomas Beach, DE 16-576.

The Commission may also desire to keep in mind the purpose and context of DERs. One purpose of encouraging DERs is to reduce the future cost of the grid to all consumers by making efficient decisions at the customer level and then at the utility level. The context for New Hampshire is a regional electric grid with related energy, capacity and other markets that give New England among the highest regional electric costs in the nation.[10] This includes ISO-New England's rapidly increasing open access transmission tariff (OATT), enlarged by billions of dollars in new transmission investment.[11] This is occurring while load is generally flat. If DERs can efficiently reduce demand for distribution investment, those savings will accumulate into reduced demand for transmission investment. It also should be apparent that impairing DERs by limiting net metering when it may be one of the several solutions to high electricity costs is not prudent, especially without data to support the change.

Does your position contradict the requirements of HB 1116?

No, although NEM has been and continues to be successful in New Hampshire, developing a long-term plan provides customers and stakeholders with greater certainty about the future of DERs, and ensures a transition to alternative rates and regulatory mechanisms occurs smoothly. Collecting data, refining methodologies, and developing pilot programs in the present will assist and inform the development of future programs and alternative mechanisms.

II. <u>Data Collection and Sharing</u>

Why are data collection and data sharing critical to this proceeding?

There are several reasons. Data collection, sharing and transparency are critical to effectively evaluate:

1. new methodologies for quantifying benefits and costs of DERs;
2. the costs and benefits of net metering, whether changes are warranted, and the costs and benefits of potential successor programs; and
3. opportunities for non-wires alternatives in the distribution system planning process;
4. alternative or pilot rate designs and billing mechanisms.

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[10] EIA, Table 5.6.B Average Price of Electricity to Ultimate Customers. *Electric Power Monthly*.

[11] One transmission provider, NextEra Energy expects New England's transmission rates to be 500% higher over a 14-year period, *see* Gibelli, S., and Gardner, M. August 16, 2016. "Delivering the benefits of competitive transmission to New England's ratepayers while balancing the need to maintain system reliability." A presentation to NEPOOL Transmission/Reliability Committee. Slide 8.

Greater data availability and transparency will enable more accurate and precise economic assessments, and ultimately lead to more informed decision making.

How is data collection and data sharing relevant to your testimony?

Later in my testimony I discuss potential changes to distribution system planning, non-wires alternatives, and potential pilots for alternative rate designs. Access to transparent data is necessary for these programs and to evaluate their value and that of other alternative proposals being considered.

What do you mean by "new methodologies for quantifying benefits and costs of DERs?"

As shown in TASC witness Tom Beach's analysis, there are a variety of cost and benefit categories that effect the net value of solar and other DERs. There is also a locational dimension to these categories that is currently often not considered due to a lack of data and quantification methodologies. For example, a DER may have a higher value on one circuit than another due to local demand profiles and capacity constraints on the distribution system. Collecting data, developing methodologies for more granular analysis and disseminating the information will help identify those opportunities and help ensure the benefits of DERs are maximized.

Do you have any suggestions for the type of data that should be collected and the sharing requirements?

Yes, a SolarCity witness in New York created a minimum set of data that would be required to develop evaluation methodologies and inform decision-making processes.[12] The recommendations are particularly useful in this proceeding. The data requirements are presented in three tables, which include the type of data request, intended use, granularity of data, and data format. The first table is related to identifying grid needs and planned investments. The second table outlines data requirements necessary to calculating hosting capacity. The final table includes data categories to calculate the locational value of DERs. The tables are attached as Exhibit EFCA-PB-3.

III. <u>Reforming Distribution System Planning</u>

What is a non-wire alternative?

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[12] Testimony of Carlos Gonzalez before the State of New York Department of Public Service. Case 16- E-0060. May 27, 2016

Non-wires alternatives is a concept of deploying generation, DERs, energy efficiency or demand response to replace or defer traditional transmission and distribution investments such as new lines and substations. Integrating non-wires alternatives into the distribution planning process presents an opportunity to leverage the value of DERs and ultimately minimize system costs.

Are New Hampshire utilities required to assess non-wires alternatives in their Least Cost Integrated Resource Plans ("LCIRP")?

Yes, RSA Sections 378.38-III and 378.38-IV require utilities to assess "supply options including owned capacity, market procurements, renewable energy, and distributed energy resources" and "assess distribution and transmission requirements, including an assessment of the benefits and costs of 'smart grid' technologies, and the institution or extension of electric utility programs designed to ensure a more reliable and resilient grid…"

To what extent have New Hampshire utilities incorporated non-wires alternatives into their LCIRPs?

Liberty Utilities proposed a hypothetical non-wires alternative to illustrate its planning process in its most recent LCIRP.[13] However the company notes there are challenges to gathering data to evaluate the potential benefits and costs,[14] and that regulatory reforms and data collection are required, along with associated cost recovery, to perform non-wires alternative evaluations.[15]

In its most recent LCIRP,[16] Unitil does not outline a process for procuring and evaluating non-wires alternatives. Unitil witness Thomas Meissner, Jr. asserted in his testimony that solar is not a good alternative to traditional utility investments.[17] Mr. Meissner uses an example of an $11.75 million substation and compares it to whether $11.75 million spent on a mix of distributed and utility scale solar could meet the capacity requirements. He concludes that the solar would be 70 times more expensive than the substation since the solar could only provide 1 MW of capacity, whereas the substation provides 70 MW. This is a flawed approach for evaluating non-wires alternatives since the company assumed it would be spending $11.75 million on solar rather than a substation.[18] Instead, the utility could have evaluated incentives, including rebates, which would encourage customers to invest in a

[13] Docket No. 16-097, Appendix E.
[14] Liberty Utilities response to EFCA 2-5.
[15] Docket No. 16-097, Appendix E at page 4.
[16] Docket No. 16-463
[17] Direct Testimony of Thomas P. Meissner, Jr. at pages 35-36.
[18] Unitil response to EFCA-UES 1-21.

portfolio of DERs, including solar, demand response and storage, in the area of the distribution need. By leveraging customer investments, the cost of the incentives could be a fraction of the cost for the utility to own and operate the non-wires alternatives. Traditional utility investments, such as substations, are also typically "lumpy" in that the infrastructure is oversized to accommodate potential load growth and long-term needs. It is unclear whether the region served by the new substation requires 70 MW in the near-term, or whether non-wires alternatives could have provided a cost-effective option for deferring the substation to future years.

Eversource noted in its most recent LCIRP that its Energy Efficiency team determines whether there are targeted conservation and load management measures.[19]

Do the utilities encourage customers to make energy-related investments at specific locations on the distribution system to help meet the reliability or efficiency needs of the local distribution system?

As noted above, Liberty Utilities studied a hypothetical case study in their LCIRP about the opportunity of targeted customer investments to reduce demand on the distribution system.[20] This appears to be the extent to which the utilities are considering the encouragement of customer investments in DER at specific locations. Unitil and Eversource have no such plans for encouraging customers to invest in DERs at specific locations at this time.[21]

What can be done to encourage more non-wires alternatives in the distribution system planning process?

The Commission and utilities can incorporate a competitive procurement process in utility LCIRPs. The utility would identify a system need and "traditional wires" solution through the LCIRP process, identify potential non-wires alternative incentives, and solicit bids from third-party providers for solutions that meet the identified need. The Commission and independent evaluator then compare the proposals in a cost-benefit analysis using the Societal Cost Test, and select the solution that is expected to provide the greatest societal benefit.

This process is similar to the generation planning approach taken in vertically-integrated states, such as Georgia, in which the utility identifies a capacity need in its integrated planning process. The utilities

[19] Docket No. 15-248
[20] Liberty Utilities response to EFCA 2-9. See also Docket No. 16-097, Appendix E.
[21] See Unitil response to EFCA 2-9, and Eversource response to EFCA 2-9.

then propose a utility-owned option and other parties bid alternative projects that meet the capacity need. The Commission and independent evaluator conduct an analysis to determine which project has the lowest system cost. If the utility's project is selected, the utility is authorized to construct the project and add it to its rate base. If an alternative is selected, the utility enters into a power-purchase agreement with the alternative supplier.

Are there other ways to encourage location-specific investments in DERs?

Utilities should also be encouraged to create and disseminate hosting capacity maps to encourage deployment. Hosting capacity maps that identify available capacity for DERs on feeders can send customers and DER providers signals about areas on the distribution system where deployment should be targeted or avoided due to scarce capacity. Unitil does not currently develop or publish hosting capacity maps.[22]

Should utilities be able to own non-wires alternatives?

No. Utility ownership of non-wires alternatives such as distributed generation and energy storage should be prohibited due to the potential conflicts of interest. DER providers would be at a competitive disadvantage because utilities have customer data, information about system needs, and could use the interconnection process to favor their projects over those proposed by third-parties. Moreover, DER providers operate in a competitive industry and could be disadvantaged if utilities are allowed to use regulated assets, such as trucks and billing software, for competitive purposes. The New York Public Service Commission decided early in the Reforming the Energy Vision process to prohibit utility ownership of DERs, unless it is a demonstration project or if a market for services does not exist, due to similar concerns.[23]

Should utilities be able to recover costs associated with non-wires alternative procurement?

Yes. As noted by Liberty Utilities in their recent LCIRP, utilities need to gather the necessary data to perform these evaluations and cost recovery is necessary to accomplish that. A valuable outcome from this proceeding would be to identify data requirements, a budget to collect the data, an implementation

[22] Eversource response to NHSEA 1-12
[23] New York: Case No. 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. Order Adopting Regulatory Policy Framework and Implementation Plan (pg. 67-68). February 26, 2015.

plan, and timelines for utilities to make this data available. Utilities should be able to recover prudently incurred costs associated with these programs.

Introducing earnings incentive mechanisms tied to procurement and success of non-wires alternatives can also encourage utilities to adopt the processes discussed herein.

Have these processes and mechanisms been used in other jurisdictions?

Yes, New York provides a good example of competitive procurement of DERs for grid needs, earnings opportunities for utilities, and the creation of hosting capacity maps.

The most prominent example of competitive procurement of DERs to defer distribution upgrades is Con Edison's Brooklyn/Queens Demand Management (BQMD) Program. Con Edison identified a potential 69 MW overload on subtransmission feeders which could be mitigated a $1 billion investment in a new substation, switching stations and subtransmission feeders.[24] As an alternative, Con Edison proposed procuring 52 MW of non-wires alternatives and 17 MW of traditional investments for $200 million, which would defer the need for a substation by several years. The non-wires alternative was approved, and Con Edison was authorized to amortize the costs of the program for 10 years.[25] Con Edison released guidelines for participating in the BQDM, which are attached as Exhibit EFCA-PB-4.

New York utilities have begun sharing locational maps on their websites to assist distributed generation providers identify areas for deployment or areas to potentially avoid. Although not yet a hosting map, Orange and Rockland Utilities provide a map to identify areas that will have higher interconnection costs.[26]

Does your recommendation align with the objectives of HB 1116 and the Commission?

Yes, HB 1116 states that the Commission "may include other regulatory mechanisms and tariffs for customer-generators." The reformed distribution system process described above can lead to the development of new programs and mechanisms to incentivize DER investment in areas with the greatest need.

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[24] New York Case No. 14-E-0302. Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn Queens Demand Management Program. Order Establishing Brooklyn/Queens Demand Management Program (December 12, 2014). Pages 2-3.
[25] Ibid at pages 26-27.
[26] Orange and Rockland Utilities interconnection map. Available from http://coned.maps.arcgis.com/apps/webappviewer/index.html?id=566397d6a395447f9ab80dc9941f0d31

The recommendation also directly aligns the New Hampshire's Public Utilities Statutes, including the aforementioned RSA Section 378.38. Section 378:37 states that meeting New Hampshire's energy needs shall be "at the lowest reasonable cost while providing for the reliability and diversity of energy sources; to maximize the use of cost effective energy efficiency and other demand side resources…" In the event that the Commission determines options in a LCIRP have "equivalent reliability, and equivalent environmental, economic, and health-related impacts", Section 378.39 provides the Commission with an order of energy policy priorities that should guide the Commission's evaluation. The order of priorities include: 1. Energy efficiency and other demand-side management resources; 2. Renewable energy sources; and 3, all other energy sources.

IV. Alternative Rate and Regulatory Mechanisms

What are some appropriate alternative rate and regulatory mechanisms for the Commission to consider in this proceeding?

Improving price signals in rates can benefit customers by changing consumption behavior or incentivizing the adoption of DERs, both of which can reduce system costs. Location-based incentives and time-of-use (TOU) rates are two potential alternatives to consider.

Please describe location-based incentives.

As previously discussed in the non-wires alternatives and distribution system planning sections, distributed energy resources potentially have higher net benefits in some locations than others. The Commission can consider a pilot that identifies high value areas and provides locational incentives, such as rebates or bill credits, for deploying DERs in those areas.

How can TOU rates send signals about system costs and opportunities for DERs?

TOU rates can be designed to send signals about the relative marginal cost, both fixed and variable, of electricity. Peak periods of high demand have higher marginal costs due to higher energy prices in the short-run and demand driving the need for additional fixed assets in the long-run. Off-peak periods coincide with lower demand and thus have lower marginal costs due to lower energy prices and the availability of excess fixed capacity. Therefore, the TOU rate is designed to charge customers a higher rate for kWh consumed during peak periods, and lower rate for consumption during off-peak periods. This signals to customers that they should shift their consumption to off-peak hours when possible.

With regard to DERs, TOU rates provide more granular, time-specific signals about the value that such resources provide to the system.

Do the New Hampshire utilities currently have TOU rates for residential customers and are there any NEM customers subscribing to those rates?

Liberty Utilities and Eversource both have optional TOU rates for residential customers, while Unitil does not. None of Eversource's NEM customers are on the utility's TOU rate,[27] and only one of Liberty Utilities' nearly 300 NEM customers is on the TOU rate.[28]

Please describe Liberty Utilities' existing TOU rate.

The optional TOU rate provided by Liberty Utilities includes a $12.28/month fixed customer charge, $0.1999/kWh on-peak charges and $0.10796/kWh off-peak charges.[29] The on-peak period is between 8am and 9pm on non-holiday weekdays, and all other hours are off-peak.

Is Liberty Utilities' existing TOU rate a viable alternative rate for the purposes of this proceeding?

While the rate does send a general signal about marginal costs, I do believe the rate should be improved. My primary concern with the rate is the length of the peak period. At thirteen hours long, it creates a challenge for customers to shift their consumption to off-peak hours. Based on the utility's hourly data since 2013, I suggest the Commission consider a TOU rate with a shorter peak period that better reflects the length of the utility's peak. The utility's hourly data[30] shows that demand within 5% of peak occurred between 11am and 6pm, and demand within 10% of peak occurred between 10am and 9pm.

Please describe Eversource's existing TOU rate.

Eversource's TOU rate includes a $29.90/month fixed customer charge, a $0.24752/kWh on-peak charge and $0.10967/kWh off-peak charges.[31] The on-peak period is between 7am and 8pm on non-holiday weekdays, and all other hours are off-peak.

Is Eversource's existing TOU rate a viable alternative rate for the purposes of this proceeding?

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[27] Eversource response to TASC 2-1
[28] Liberty Utilities response to Staff 2-13
[29] Liberty Utilities response to NERA 1-3 attachment, pg. 16.
[30] Liberty Utilities response to OCA 1-3
[31] Eversource response to NERA 1-3 attachment, pg. 12.

Like Liberty Utilities' optional TOU, I believe Eversource's rate does send a general signal about marginal costs but think the rate must be improved. The 13 hour length of the peak period is a concern because of the challenges it poses for customers to shift their consumption to off-peak hours. Based on the utility's hourly data since 2013, I suggest the Commission consider a TOU rate with a shorter peak period that better reflects the length of the utility's peak. The utility's hourly data[32] shows that demand within 5% of peak occurred between 12pm and 7pm, and demand within 10% of peak occurred between 10am and 9pm. An additional concern is the high fixed customer charge.

Why are fixed charges a concern?

With regard to DERs and energy efficiency, high fixed charges reduce the incentive for customers to invest in these technologies because fixed charges reduce potential bill savings. Increasing fixed charges also harms customers that have already invested in DERs and energy efficiency because the charges reduce the value of their investments.

There are other ways that fixed charges harm customers as noted in a recent report by *Synapse Energy Economics*.[33] Fixed charges limit a customer's ability to control their energy bills, harm low-use customers the most, disproportionally impacts low-income customers, and can ultimately lead to increased system costs, since lower the volumetric charges (c/kWh) associated with fixed charges can lead to greater total electricity consumption.

If Unitil had an optional TOU rate, what would be an appropriate peak period?

Data from Unitil's peak days shows that hours with demand within 5% of the peak occurred between 12pm and 6pm, and hours with demand within 10% of the peak occurred between 10am and 8pm.[34] A TOU rate with peak periods within these ranges is appropriate.

Is Unitil's demand charge proposal an appropriate alternative?

Unitil proposes that DG customers be moved to a separate class of service and to three part rates that includes demand charges based on the customer's peak demand over a 15-minute period.[35] Mandatory demand charges are problematic for DG customers, or any residential customer, for that matter.

[32] Eversource response to OCA 1-3
[33] Whited, M., Woolf, T., Daniel, J. 2016. *Caught in a Fix: The Problem with Fixed Charges for Electricity*. Synapse Energy Economics. Available from: http://www.synapse-energy.com/sites/default/files/Caught-in-a-Fix.pdf
[34] Unitil response to OCA 1-3.

A residential customer's demand is a function of many factors, including the weather, R-value of their home, types and efficiency of appliances, and the customer's consumption behavior. Their demand can vary widely from hour to hour and day to day, making it burdensome for customers to monitor their demand in 15-minute increments. It can also reduce investment in energy efficiency and DER because customers cannot realize bill savings.

For example, Figure 1 below shows a hypothetical example of how a move to demand charges can change a customer's bill.[36] Customers with lower load factors would likely see substantial increases in their bills, while customers with higher load factors would realize bill savings. For lower load factor customers, demand charges can wipe out any potential savings from energy efficiency and DER investments. If a customer that consumes 600 kWh in one month invests in energy efficiency, and the next month consumes 500 kWh, they would save $11 under the volumetric rate design. A shift to demand rates after that investment would increase the customer's monthly bill by $20, thus wiping out their bill savings and then some.

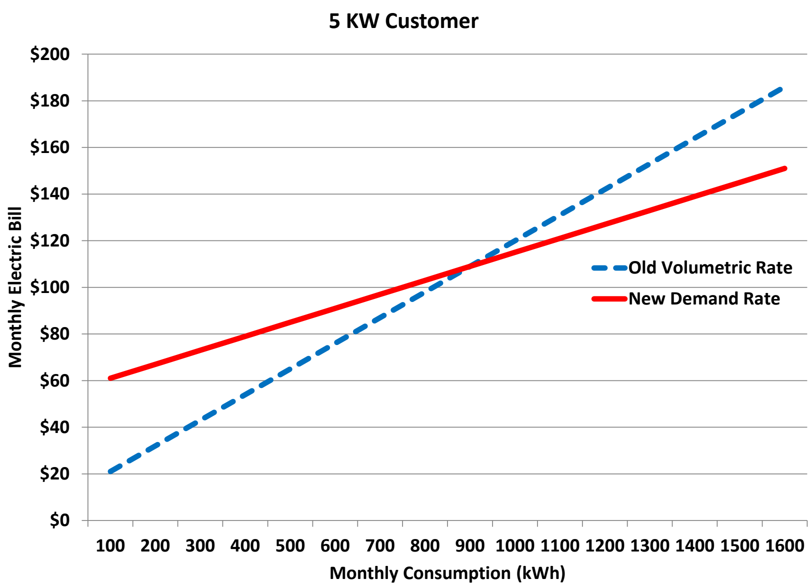

Figure 1 – A comparison of a customer's monthly electricity bill under a two-part rate ("Old Volumetric Rate") and a three-part rate ("New Demand Rate"). The figure shows the bill for a 5 kW of demand and varying levels of kWh consumption.

[35] Testimony of H. Edwin Overcast, Exhibit HEO-1, pages 7 and 22.
[36] The example is for customers with 5 kW of demand and across a range of kWh consumption, and the rates are from a *Brattle Group* example. Hledik, R., 2015. *Rolling out Demand Charges*. Presentation available from: http://www.brattle.com/system/publications/pdfs/000/005/170/original/Rolling_Out_Residential_Demand_Charges_Hledik_EUCI.pdf?1431628444

Demand and fixed charges are, in a sense, the antithesis of revenue decoupling. With demand and higher fixed charges, a customer's electricity bill is decoupled from their total electricity consumption, while revenue decoupling decouples a utility's revenues from its electricity sales. Both mechanisms provide the utility with more revenue certainty, but only revenue decoupling ensures residential customers can confidently invest in energy efficiency and DERs.

Are there additional concerns with implementing mandatory demand charges?

Yes, implementing demand charges also present potential unintended consequences. First, total electricity consumption could increase because customers pay a lower volumetric rate with demand charges.[37] This means that every incremental kWh that doesn't contribute to the customer's peak is cheaper than on rates without demand charges (as evidenced by the relative steepness of the slopes in Figure 1). Second, demand charges can disincentivize high wattage appliances, including electric heat, hot water heaters, dryers, and stoves. Customers with the means of converting to natural gas-fired appliances would be able to realize savings, leaving customers unable to convert to natural gas on the hook for more system costs. In other words, use of demand charges creates a potential cost-shift.

Does Unitil's demand charge proposal meet the criteria set forth in HB 1116?

No it does not. Unitil or its witnesses did not provide any cost-benefit analysis showing that such a change in rate design is warranted,[38] or how the proposed rate design could affect investment in energy efficiency and DERs.[39] For these reasons and those stated above, demand charges violate the legislative purposes of HB 1116, including, among other things, "the continuance of reasonable opportunities for electric customers to invest in and interconnect customer-generator facilities."[40]

V. <u>Pilot Programs</u>

In conclusion, do you have suggestions for potential pilot programs?

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[37] A simulation of potential impacts by *Brattle Group* found a 0.2% increase in consumption of average residential load profile. *See* Hledik, R., 2015. *Rolling out Demand Charges*. Page 14 (slide 13). Presentation available from: http://www.brattle.com/system/publications/pdfs/000/005/170/original/Rolling_Out_Residential_Demand_Charges_Hledik_EUCI.pdf?1431628444

[38] Unitil response to Staff-UES-10

[39] Unitil response to EFCA-UES 1-27.

[40] DE 16-576, pg. 2.

Yes, I suggest that the Commission consider two pilot programs. The first is a non-wires alternative pilot in which each utility identifies an area of grid need and encourages customers to invest in DERs in that location. This program can gain insights into the process of subscribing and evaluating non-wires alternatives, how DERs can provide grid services or defer potential investments, and how customers and DER providers respond to different signals (whether they are incentives or marketing materials).

I also recommend a residential TOU pilot program. Although Eversource and Liberty Utilities both have optional TOU rates, they can be improved by creating a shorter peak period that more closely aligns with the system peak and allows customers to more easily shift consumption to off-peak periods. The pilot should be open to all customers in order to gain a better understanding about how different customers (such as apartment dwellers, single family homes, low-income, solar customers, or customers with electric vehicles, etc.) are impacted by the rates, how they respond to signals and educational materials, and ultimately how their consumption behaviors change.

Finally, while the pilot programs are ongoing, I recommend that NEM be reviewed every few years with a cost-benefit analysis that utilizes the best available data and information at the time.

Does this conclude your testimony?

Yes it does.

Patrick Bean

601 13th Street NW, Washington, DC 20005

PROFESSIONAL EXPERIENCE

Deputy Director of Policy and Electricity Markets at SolarCity (Washington, DC) **10/2015 – Present**

- Providing quantitative analysis of electricity markets, utility rate designs and distributed energy resource policies.
- Participates in a variety of utility regulatory proceedings including rate cases, grid modernizations, and distributed energy resource programs.
- Provides expert testimony and written comments for regulatory proceedings.

Senior Research Associate at KAPSARC (Riyadh, Saudi Arabia) **6/2013 – 9/2015**

- Managed KAPSARC's Utilities of the Future research which focuses on electricity business and regulatory models, and the development of quantitative simulation tools.
- Developed a simulation platform for distributed energy resource planning and solar adoption.
- Provided economic assessments of renewable energy technologies and policy incentives.
- Taught a two-day electricity markets training course to more than 30 international researchers.
- Co-authored several white papers and policy briefs about electricity markets, renewable energy, and energy productivity.

Senior Energy Policy Advisor at The American Clean Skies Foundation (Washington, DC) **1/2012 – 5/2013**

- Managed analytical assessments of commercial and policy mechanisms that promoted the use of natural gas, renewables and energy efficiency.
- Regularly presented electricity market analysis and insights to state utility regulators at NARUC events.
- Developed quantitative tools to identify coal plants at risk for retirement.
- Advised a variety of stakeholders on utility rate cases, and generation certification filings.
- Co-authored public comments for regulatory filings (FERC, DOE, EPA), several reports, and essays.

Strategic Generation Planning Analyst at Southern Company (Birmingham, AL) **1/2009 – 1/2012**

- Developed a new generation planning method to manage market uncertainty and minimize regrets.
- Led the development and communication of quantitative environmental policy analysis.
- Analyzed potential environmental compliance plans and recommended strategies.
- Conducted economic analyses of generation options (new-builds, retirements, and retrofits) for regulatory filings including rate cases, integrated resource plans, and generation certification filings.
- Evaluated potential merger and acquisition targets for executives.

Energy Analyst at The Nicholas Institute/CCPP at Duke University **6/2008 – 12/2008**

- Modeled proposed climate legislation to investigate potential implications for the natural gas market and co-authored a report at the request of our Fortune 500 corporate partners.
- Co-authored a report that investigated biofuel policies and their interactions with climate policies.

EDUCATION

Duke University, Durham, NC

M.E.M in Energy and Environmental Resources, December 2008 GPA: 3.58

Master's Project: "Evaluating the Economics of Ethanol" Advisor: Dr. Richard Newell

Marist College, Poughkeepsie, NY
B.S. in Environmental Science and Policy (*Magna Cum Laude*), May 2006
Minor: Political Science GPA: 3.63

PUBLICATIONS

Adjali, I., Bean, P., Fuentes, R., Kimbrough, S.O., Muaafa, M., Murphy, Frederic. (2016). *Can Adoption of Rooftop Solar PV Panels Trigger a Utility Death Spiral? A Tale of Two Cities*. KAPSARC Discussion Paper.

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Galik, C.S., Hodgson, W.C., Raborn, C., Bean, P.T. (2009). *Integrating Biofuels into Comprehensive Climate Policy – an Overview of Biofuels Policy Options*. Climate Change Policy Partnership Discussion Paper 09-07, Duke University.

Hoppock, D., Bean, P., Williams, E. (2009). *The Influence of Technology and a Carbon Cap on Natural Gas Markets*. Climate Change Policy Partnership Discussion Paper 09-02, Duke University.

HONORS

Southern Company Excellence Award	**2011**
Marist College Intern Student of the Year	**2006**
Marist College School of Science Intern Student of the Year	**2006**
Mary Lou Gantert Award for Excellence in Science	**2006**
CH Energy Group Award for Excellence in Environmental Science	**2006**
Who's Who in American Colleges and Universities	**2006**
Sigma Zeta National Science and Mathematics Honor Society	**2006**
Men's Lacrosse MAAC All-Academic Team	**2004**

A Pathway to the Distributed Grid

Evaluating the economics of distributed energy resources and outlining a pathway to capturing their potential value

SolarCity

Grid Engineering

White Paper

Executive Summary

Designing the electric grid for the 21st century is one of today's most important and exciting societal challenges. Regulators, legislators, utilities, and private industry are evaluating ways to both modernize the aging grid and decarbonize our electricity supply, while also enabling customer choice, increasing resiliency and reliability, and improving public safety, all at an affordable cost.

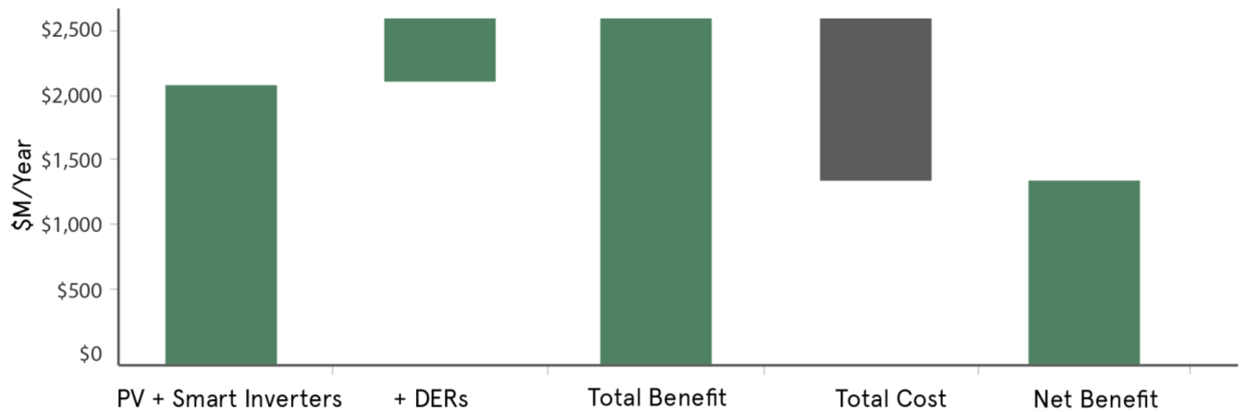
However, modernizing an aging grid will require significant investments over and above those seen in any recent period – potentially exceeding $1.5 trillion in the U.S. between 2010-2030.[1] Given the large sums of ratepayer funds at stake and the long-term impact of today's decisions, it is imperative that such investment is deployed wisely, cost-effectively, and in ways that leverage the best technology and take advantage of customers' desire to manage their own energy.

In this report, we explore the capability of distributed energy resources (DERs) to maximize ratepayer benefits while modernizing the grid. First, we quantify the net societal benefits from proactively leveraging DERs deployed in the next five years, which we calculate to be worth over $1.4 billion a year in California alone by 2020. Then, we apply this methodology to the most recently available Investor Owned Utility (IOU) General Rate Case (GRC) filing – Pacific Gas and Electric's 2017 GRC – in order to evaluate whether DERs can cost effectively replace real-world planned distribution capacity projects. Finally, we evaluate the impediments to capturing these benefits in practice. These structural impediments undermine the deployment of optimal solutions and pose economic risk to consumers, who ultimately bear the burden of an expensive grid. Accordingly, we suggest several ways to overcome these impediments by improving the prevailing utility regulatory and planning models.

Distributed Energy Resources Offer a Better Alternative

This report presents an economic analysis of building and operating a 21st century power grid – a grid that harnesses the full potential of distributed energy resources such as rooftop solar, smart inverters, energy storage, energy efficiency, and controllable loads. We find that an electric grid leveraging DERs offers an economically better alternative to the centralized design of today. DERs bring greater total economic benefits at lower cost, enable more affordability and consumer choice, and improve flexibility in grid planning and operations, all while facilitating the de-carbonization of our electricity supply.

Over $1.4 Billion per Year in Net Societal Benefits from DERs by 2020



February 2016

To evaluate the potential benefits, we build on existing industry methodologies to quantify the net societal benefits of DERs. Specifically, we borrow the *Net Societal Costs/Benefits* framework from the Electric Power Research Institute (EPRI),[2] incorporating commonly recognized benefit and cost categories, while also proposing methodologies for several hard-to-quantify benefit categories that are often excluded from traditional analyses. Next, we incorporate costs related to the deployment and utilization of DERs, including integration costs at the bulk system and distribution levels, DER equipment costs, and utility program management costs. Using this structure, we quantify Net Societal Benefits of more than $1.4 billion a year by 2020 for California alone from DER assets deployed in the 2016-2020 timeframe, as depicted in the previous figure.

In addition to evaluating net societal benefits at the system level, we consider the benefits of DER solutions for specific distribution projects in order to evaluate whether DERs can actually defer or replace planned utility investments in practice. Specifically, we apply the relevant set of cost and benefit categories to the actual distribution investment plans from California's most recently available GRC filing, which is PG&E's 2017 General Rate Case Phase I filing. This real-world case study assesses a commonly voiced critique of utilizing DERs in place of traditional utility infrastructure investments: that not all avoided cost categories are applicable for every distribution project, or that DERs only provide a subset of their potential benefits in any specific project. Therefore, we consider only a subset of utility-applicable avoided cost categories when assessing the set of distribution infrastructure projects in PG&E's 2017 GRC filing; we also utilize PG&E's own avoided cost values rather than our own assumptions. Even using PG&E's conservative assumptions on this subset of benefits, we quantify a net benefit for DER solutions used to replace the distribution capacity investments in PG&E's 2017 GRC.

Utility Regulatory Incentives Must Change in Order to Capture DER Benefits

While our analysis shows net societal benefits from DERs, both at the societal and distribution project levels, under the prevailing utility regulatory model DER benefits cannot be fully captured. Instead, utilities have a fundamental financial incentive of "build more to profit more", which conflicts with the public interest of building and maintaining an affordable grid. Under today's regulatory paradigm, utilities see a negative financial impact from utilizing resources for distribution services that they do not own – which includes the vast majority of distributed energy resources – even if those assets would deliver higher benefits at lower cost to ratepayers. This financial incentive model is a vestige of how utilities have always been regulated, a model originally constructed to encourage the expansion of electricity access. However, in this age of customers managing their energy via DERs, this regulatory model is outdated. This report offers a pathway to removing this structural obstacle, calling for a regulatory model that neutralizes the conflict of incentives facing utilities. While separating the role of grid planning and sourcing from the role of grid asset owner – such as through the creation of an independent distribution system operator (IDSO) – would achieve this objective, some states may choose not to implement an IDSO model at this time. In these instances, this paper proposes the creation of a new utility sourcing model, which we call *Infrastructure-as-a-Service*, that allows utility shareholders to derive income, or a rate of return, from competitively sourced third-party services. This updated model would help reduce the financial disincentive that currently biases utility decision-making against DERs, encouraging utilities to deploy grid investments that maximize ratepayer benefits regardless of their ownership.

Grid Planning Must be Modernized in Order to Capture DER Benefits

A second structural impediment to realizing DER benefits is the current grid planning approach, which biases grid design toward traditional infrastructure rather than distributed alternatives, even if distributed solutions better meet grid needs. Combined with the "build more to profit more" financial incentive challenge, current grid planning can encourage 'gold-plating', or overinvestment, in grid infrastructure. Furthermore, outdated planning approaches rely on static assumptions about DER capabilities and focus primarily on mitigating potential integration challenges rather than proactively harnessing these flexible assets. This report offers a pathway to modernizing grid planning, calling for the utilization of an *Integrated Distribution Planning* approach that encourages incorporating DERs into every aspect of planning, rather than merely accommodating DER interconnection. Additionally, transparency into grid needs and planned investments is fundamental to realizing benefits. As such, this report recommends a data transparency approach that invites broad stakeholder engagement and increases industry competition in providing grid solutions.

Key Takeaways

1. Distributed energy resources offer <u>*net economic benefits to society*</u> worth more than $1.4 billion per year in California alone by 2020, including benefits related to voltage and power quality, conservation voltage reduction, grid reliability and resiliency, equipment life extension, and reduced energy prices.

2. To realize these benefits, the *utility regulatory incentive model* must change to take advantage of customer choices to manage their own energy. Utility incentives should promote best-fit, least-cost investment decisions regardless of service supplier – eliminating the current bias toward utility-owned investments.
3. Utility planning approaches must also be modernized to capture these benefits. Utilization of an *integrated distribution planning* framework will unlock the economic promise of distributed energy resources, while widely sharing utility grid data in standard data formats will invite broader stakeholder engagement and competition.

Recommendations and Next Steps

Our ultimate goal is to help provide concrete evidence and recommendations needed by regulators, legislatures, utilities, DER providers, and industry stakeholders to transition to a cleaner, more affordable and resilient grid. While the details of implementing these recommendations would vary from state to state, we see the following as promising steps forward for all industry stakeholders in modernizing our grid:

1. Future regulatory proceedings and policy venues related to capturing the benefits of DERs should *incorporate the expanded benefit and cost categories* identified in this paper.
2. Regulators should look for near-term opportunities to *modernize the utility incentive model*, either for all utility earnings or at a minimum for demonstration projects, to eliminate the bias toward utility-owned investments.
3. Regulators should require utilities to *modernize their planning processes* to integrate and leverage distributed energy resources, utilizing the integrated distribution planning process identified in this paper.
4. Regulators should require utilities to *categorize all planned distribution investments* in terms of the underlying grid need. Utilities should make data available electronically to industry, ideally in a machine-readable format.

Call for Input

We offer this paper as an effort to support the utilization of grid modernization to maximize ratepayer benefits. The cost/benefit analysis we develop here is an effort meant to expand the industry's ability to quantify the holistic contribution that DERs offer to the grid and its customers, extending the familiar cost/benefit framework beyond PV-only analyses and into full smart inverter and DER portfolios. Furthermore, we recognize that important regulatory proceedings – such as the CPUC Distribution Resource Plans (DRP) and CPUC Integrated Distributed Energy Resources (IDER) – will play an important role in giving stakeholders the tools to calculate the value of DERs, and offer this paper a as resource in those efforts.

No single report could adequately address all the issues – engineering, economic, regulatory – that naturally arise during such a transformative time in the industry. By compiling the major issues in one place, we attempt to advance the discussion and suggest that this paper includes a "table of contents" of critical topics for regulators and industry stakeholders to consider when evaluating the full potential of distributed energy resources.

There are many details of this paper that can be refined, including utilizing more complete data sets to inform the cost/benefit analysis. We welcome ongoing dialogues with utilities and other stakeholders to improve the assumptions or calculations herein, including sharing data and revising methodologies to arrive at more representative figures. In fact, most of the authors of this paper are former utility engineers, economists, technologists, and policy analysts, and would value the opportunity to collaborate. We welcome a constructive dialogue, and can be reached at gridx@solarcity.com.

Acknowledgements

We would like to thank the following industry stakeholders who were willing to provide their valuable feedback on the content of this paper. While we incorporated their input to every extent possible, we, the authors, are solely responsible for the information presented and the conclusions drawn in the report.

Jon Wellinghoff
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Rocky Mountain Institute

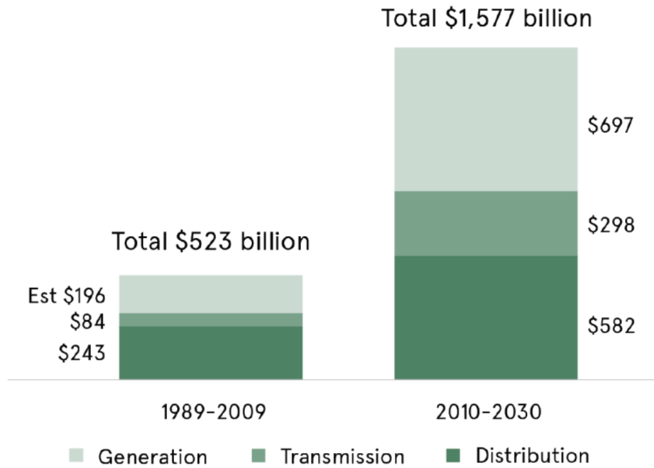
Michael O'Boyle
Energy Innovation

I. Introduction

Grid Investments are Increasing

Grid infrastructure planners are responsible for some of the most significant infrastructure investments in the United States. As of 2011, U.S. utilities had almost half a trillion dollars of undepreciated transmission, distribution and generation assets on their balance sheets, growing at a rate of 6 to 8% per year.[3] As depicted in the adjacent figure, the Edison Electric Institute forecasts that another $879 billion dollars in distribution and transmission investments alone will occur in the twenty year period of 2010 through 2030 – about $44 billion dollars per year – significantly larger than investments seen in the previous 20 year period.[4] Grid investments have a significant and increasing impact on the total electricity costs faced by U.S. consumers.

U.S. Grid Investments



In light of this huge level of grid investment occurring over the next few decades, an imperative exists to ensure that these investments are deployed to maximize ratepayer benefits. There has been relatively little focus to date on how to effectively focus and reduce these infrastructure costs, particularly in the areas of transmission and distribution planning, despite the fact that they often make up half of the average residential customer's bill. This level of investment calls for a reexamination of the technological solutions available to meet the grid's needs and an overhaul of the planning process that deploys these solutions. States like California and New York have begun this process, primarily spurred by a focus on how distribution planning and operations may evolve in a future with high penetration of distributed resources.[5] While these nascent discussions and rulemakings are positive first steps, the planning framework for grid modernization must change considerably to avoid costing ratepayers billions in unnecessary, underutilized investments.

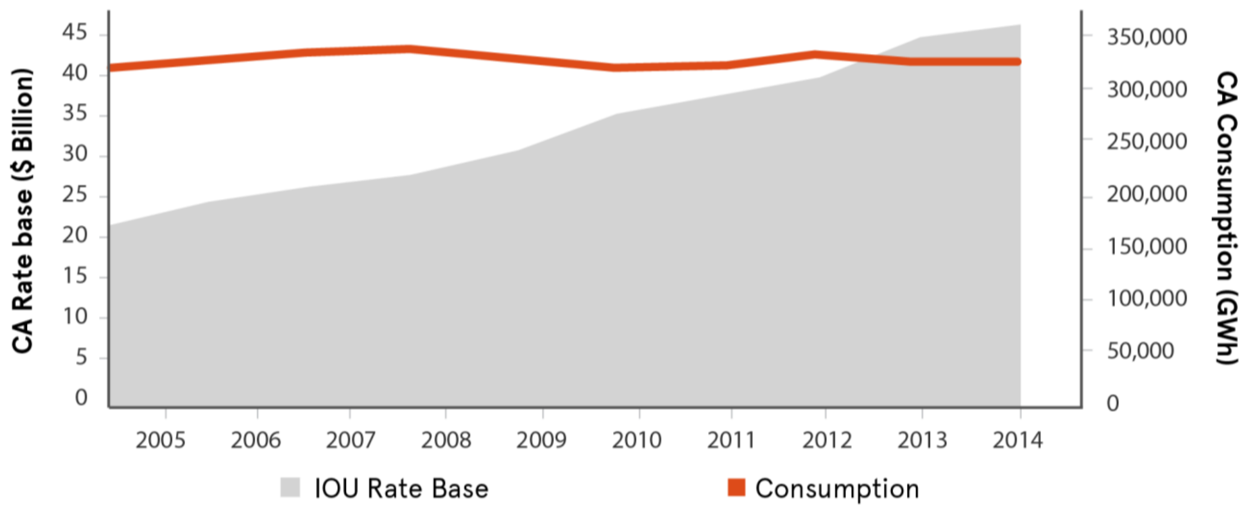
Current Utility Regulatory Model Incents a *Build More to Profit More* Approach

The current utility regulatory model, which was designed around a monopoly utility managing all aspects of grid design and operation, is outdated and unsuited for today's reality of consumers installing DERs that can benefit the grid. Therefore, industry fundamentals need to be reexamined, and the utility incentive model is a key place to start.

Electric utilities are generally regulated under a "cost plus" model, which compensates utilities with an authorized rate of return on prudent capital investments made to provide electricity services. While this model makes sense when faced with a regulated firm operating in a natural monopoly, it is well known to result in a number of economic inefficiencies, as perhaps best analyzed by Jean Tirole in his Nobel Prize winning work on market power and regulation.[6]

One fundamental problem resulting from the "cost plus" utility regulatory model is that utilities are generally discouraged from utilizing infrastructure resources that are not owned by the utility, even if competitive alternatives could deliver improved levels of service at a lower cost to ratepayers. Beyond regulatory oversight, this model contains no inherent downward economic pressure on the size of the utility rate base, or the cumulative amount of assets upon which the utility earns a rate of return. As such, utility rate bases have consistently and steadily grown over time. For example, the following chart depicts the size and recent growth of the electricity rate base for California investor-owned utilities, which continues to significantly grow even in the presence of flat electricity consumption. In short, the fundamental incentive utilities have to build more utility-owned infrastructure in order to profit more conflicts with the public interest as the grid becomes more customer-centric and distributed.

Trends in Rate Base for California Investor-Owned Utilities[7,8]



Traditional Grid Planning Focuses on Traditional Assets

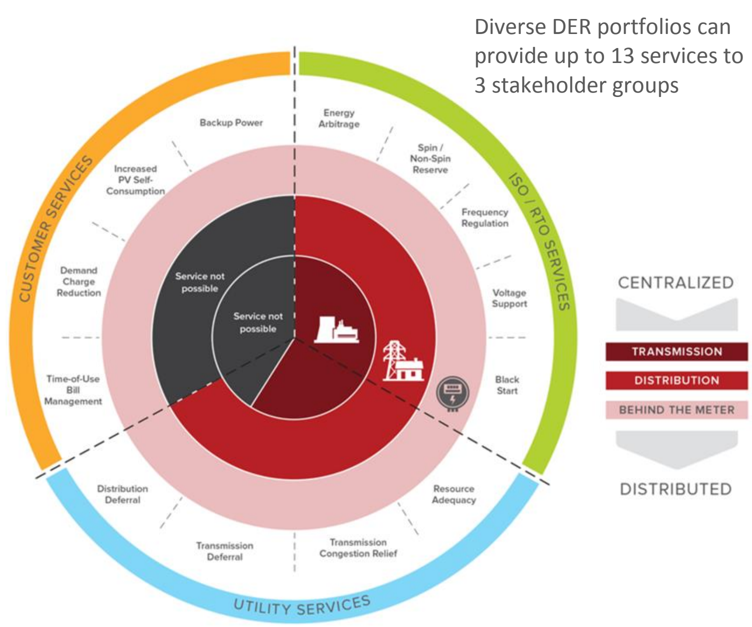
Grid planning for infrastructure investments has historically focused on installing expensive, large assets that provide service over a wide geographic region. This structure naturally evolved from the technology and market characteristics of the original electricity industry, including a natural monopoly, centralized generation, long infrastructure lead times, high capital costs with significant economies of scale, and a concentration of technical know-how within the utility.

Many of these barriers have been eliminated with the technological advancement in physical infrastructure options – such as DER portfolios that can meet grid needs – and increased sophistication of grid design and operational tools. However, grid planning remains focused on utilizing traditional infrastructure to the detriment of harnessing the increasing availability of DERs. Utilizing DER solutions will require a shift in grid planning approaches, as well as increased access to the underlying planning and operational data needed to enable DERs to operate most effectively in concert with the grid.

Distributed Energy Resources Offer Increased Grid Flexibility

Distributed energy resources include assets such as rooftop PV, smart inverters, controllable loads, permanent load shifting, combined heat and power generators, electric vehicles, and energy efficiency resources. These resources provide a host of benefits to the customer, utility, and transmission operator as identified by numerous research organizations including EPRI and the Rocky Mountain Institute (RMI). As depicted in the RMI figure to the right, diverse portfolios of DERs offer a wide range of grid services at the distribution, transmission, and customer levels.[9]

Distributed energy resources can offer deferral and avoidance of planned grid investments, improved grid resiliency, and increased customer choice. DERs, if deployed effectively and placed on equal footing in the planning process with traditional grid investments, can ultimately lead to increased net benefits for ratepayers.



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II. Distributed Energy Resources Offer a Better Alternative

Motivated by the challenge faced in designing a grid appropriate to the 21st century, this report first focuses on determining the quantifiable net economic benefits that DERs can offer to society. The approach taken builds on existing avoided cost methodologies – which have already been applied to DERs by industry leaders – while introducing updated methods to hard-to-quantify DER benefit categories that are excluded from traditional analyses. While the final net benefit calculation derived in this report is specific to California, the overall methodological advancements developed here are applicable across the U.S. Moreover, the ultimate conclusion from this analysis – that DERs offer a better alternative to many traditional infrastructure solutions in advancing the 21st century grid – should also hold true across the U.S., although the exact net benefits of DERs will vary across regions.

A. Methodology

The methodology utilized in this paper is built upon well-established frameworks for valuing policies, programs and resources – frameworks that are grounded in the quantification of the costs and benefits of distributed energy resources. Specifically, the methodology employed here:

1. Begins with the Electric Power Research Institute's 2015 Integrated Grid/Cost Benefit Framework in order to quantify total net societal costs and benefits in a framework that applies nationally. [10]
2. Quantifies the benefits for the state of California, where the modeling of individual cost and benefit categories is possible using the California Public Utilities Commission 2015 Net Energy Metering Successor Public Tool.[11] Within the context of California, this report's DER avoided cost methodology is expanded beyond EPRI's base methodology to incorporate commonly recognized (although not always quantified) categories of benefits and costs, while also proposing methodologies for several hard-to-quantify categories using the Public Tool.
3. Incorporates the full costs of DER integration, including DER integration cost data as identified by California utilities in their 2015 Distribution Resource Plans[12] to determine the net benefits of achieving 2020 penetration levels.
4. Repeats the methodology in a concrete case study by applying it to the planned distribution capacity projects from the most recent Phase I General Rate Case in California.

Enhancing Traditional Cost/Benefit Analysis and Describing Benefits as Avoided Cost

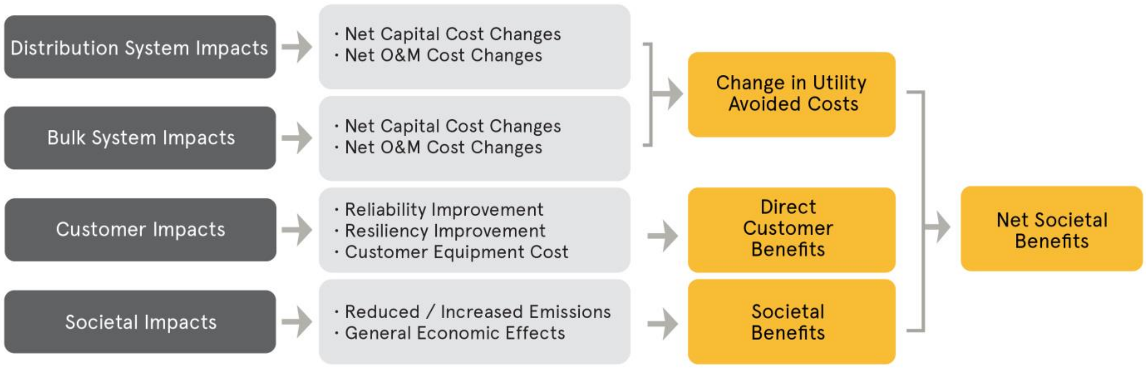
Cost/benefit analyses have been conducted for many decades to evaluate everything from utility-owned generation to utility-administered customer programs such as energy efficiency rebates and demand response program funding. This paper replicates established methodologies wherever possible, and offers new or enhanced methodologies where appropriate to consider new benefit categories that are novel to customer-driven adoption of DERs, and therefore often excluded from traditional analyses.

A key component of cost/benefit analysis commonly used for valuing the benefits of DER is the avoided cost concept, which considers the benefits of a policy pathway by quantifying the reduction in costs that would otherwise be incurred in a business-as-usual trajectory. While avoided cost calculations can be performed with varying scopes,[13] there is some degree of consensus on what the appropriate value categories are in a comprehensive avoided cost study. Groups like IREC,[14] RMI[15] and EPRI[16] have attempted to take these standard valuation frameworks even further, describing general methods for valuing some of the benefit categories that are often excluded from traditional analyses.

Each step taken by researchers to enhance previously used avoided cost methodologies advances the industry beyond outdated historical paradigms. DER-specific methodological updates include the consideration of new types of avoided costs that could be provided by distributed resources, or a revision of the assumption that resources adopted by customers are uncontrollable, passive deliverers of value to the grid and that proactive planning and policies cannot or will not be implemented to maximize the value of these grid-interactive resources.

This report continues the discussion using EPRI's 2015 Integrated Grid/Cost Benefit Framework as a springboard. EPRI's framework, depicted in the following image) was chosen as it is the most recently published comprehensive cost/benefit analysis framework for DERs. This report assumes a basic familiarity with EPRI's methodology – or avoided cost methodologies in general – on the part of the reader, although explanations of each cost or benefit category are included in the following section.

EPRI Cost/Benefit Framework[17]



The Value of DERs within California

While the overall methodology enhanced within this report is applicable nationwide, the focus of this report's economic valuation of DERs in the cost/benefit analysis is limited to the state of California. For California's NEM 2.0 proceeding, the energy consulting firm Energy+Environmental Economics (E3) created a sophisticated model that parties used to determine the impact of various rate design proposals. A major component of this model was the ability to assess DER avoided costs under different input assumptions. The more traditional avoided cost values in this paper are derived from the inputs used in the NEM 2.0 proposal filing of The Alliance of Solar Choice (TASC) for the E3 model, which is available publicly online.[18]

Additionally, benefit and cost categories for DERs – along with accompanying data and quantification methods – are being developed in the CPUC Distribution Resource Plans (DRP) proceeding. This update of the DER valuation framework in the DRP proceeding, however, is not present in the existing methodologies being used to quantify the benefits of rooftop solar in California as part of the NEM 2.0 proceeding due to the concurrent timing of the two proceedings. This report bridges these two connected proceedings in its economic analysis of the value of DERs within California.

While evaluating net societal benefits at the system level in California is a key step in understanding the total potential value of DERs, there remains much discussion within the industry regarding whether calculated net benefits can actually be realized from changes in transmission and distribution investment planning. To this end, this analysis applies the developed California DER valuation framework to a real-world case study utilizing the latest GRC filed in California, PG&E's 2017 General Rate Case Phase I filing. By utilizing this third dataset, in addition to the NEM 2.0 and DRP proceedings, this analysis delivers a comprehensive and up-to-date consideration of the potential value DERs can provide to the grid.

Analysis Scope, Assumed Scenario, and End State

This report evaluates the benefits of customer DER adoption, the associated costs, and the resulting net benefit/cost.

DESCRIPTION OF SCOPE

Net Societal Benefit = Societal Benefits – Societal Costs	
Societal Benefits	The benefits that would be generated if California achieved high-penetration of distributed energy resources.
Societal Costs	The investment cost that would be necessary to enable California to achieve high-penetration of distributed energy resources.
Net Societal Benefits	The value to society of achieving a high-penetration California defined as the benefits of the outcome less the costs of achieving the outcome.

The benefits and costs of DER are highly dependent on penetration levels. Therefore, this analysis utilizes a set of common assumptions for expected DER penetration, and specifies a market end state scenario upon which benefits and costs are quantified. The end-state assumed in this report utilizes scenarios in Southern California Edison's (SCE) July 1, 2015 Distribution Resource Plan, which includes DER adoption levels and integration cost estimates for the 2016-2020 period. These integration costs inform DER penetration assumptions, which are applied consistently across the benefits calculations to ensure that the costs of low penetration are not attributed to the benefits of high penetration, and vice-versa.

Incremental DER Adoption Scenario for 2016-2020

TECHNOLOGY	QUANTITY
Solar	4.5 GW
With Storage	900 MWh (10% Adoption)
With Load Control	150 MW (20% Adoption)

To simplify the discussion, solar deployment is focused on the years 2016-2020, adopting the penetration levels and costs associated with the TASC reference case as filed in the CPUC NEM 2.0 proposal filing, which corresponds approximately to SCE's Distribution Resource Plan Scenario 3. Of the approximately 900,000 new solar installations expected to be deployed during this period, SolarCity estimates 10% would adopt residential storage devices and 20% would adopt controllable loads (assumptions are based on customer engagement experience and customer surveys). These adoptions are central to the ability of customer DER deployments to defer and avoid traditional infrastructure investments as assessed in this paper.

The assumptions described above are used to complete the cost/benefit analysis of DERs for the whole of California. After evaluating net societal benefits at the system level, the methodology is then applied to a particular case study of actual distribution projects proposed under the latest GRC filed within California, PG&E's 2017 General Rate Case Phase I filing.

In the following sections, the deployment scenario is evaluated both qualitatively and quantitatively under a cost-benefit framework that is grounded in established methodologies, but enhanced to consider the impact of such a large change in the way the electric system is operated. The study consolidates a range of existing analyses, reports and methodologies on DERs into one place, supporting a holistic assessment of the energy policy pathways in front of policy-makers today.

B. Avoided Cost Categories

The avoided cost categories evaluated in this report are summarized in the following table. The first seven categories are included within traditional cost-benefit analyses, and as such are not substantially extended in this report (see Appendix for methodological overviews and TASC NEM Successor Tariff filing for comprehensive descriptions and rationale on assumptions[19]). The next five categories (in yellow highlight) represent new methodology enhancements to hard-to-quantify avoided cost categories (i.e. benefit categories) that are often excluded from traditional analyses. In this section, we detail the methodology and rationale for quantifying these five avoided cost categories.

AVOIDED COST	DESCRIPTION
Energy + Losses	The value of wholesale energy that would otherwise be generated in the absence of DERs, adjusted for losses that would occur. In CA, the cost of carbon allowances from the Cap and Trade program is embedded in the wholesale energy value
Generation Capacity	The value of avoiding the need for system generation capacity resources to meet peak load and planning reserve requirements
Transmission Capacity	The value of avoiding the need to expand transmission capacity to meet peak loads
Distribution Capacity	The value of avoiding the need to expand distribution capacity to meet peak loads
Ancillary Services	The value of a reduced need for operational reserves based on load reduction through DERs
Renewable Energy Compliance	The value of reducing procurement requirements for renewable energy credits, due to reduced delivery of retail energy on which RPS compliance levels are based
Societal Benefits	The value of benefits that accrue to society, and are not costs directly avoided by the utility
Voltage and Power Quality	The value of avoiding or reducing the cost required to maintain voltage and frequency within acceptable ranges for customer service
Conservation Voltage Reduction	The value of enabling conservation voltage reduction benefits by providing localized voltage support
Equipment Life Extension	The value of extending the useful life and improving the efficiency of distribution infrastructure by reducing load and thermal stress equipment
Reliability & Resiliency	The value of avoiding or reducing the impact outages have on customers
Market Price Suppression	The value of reducing the electric demand in the market, hence reducing market clearing prices for all consumers of electricity

Voltage, Reactive Power, and Power Quality Support

Solar PV and battery energy storage with 'smart' or advanced inverters are capable of providing reactive power and voltage support, both at the bulk power and local distribution levels. At the bulk power level, smart inverters can provide reactive power support for steady-state and transient events, services traditionally supplied by large capacitor banks, dynamic reactive power support, and synchronous condensers. For example, in Southern California the abrupt retirement of the San Onofre Nuclear Generation Station (SONGS) in 2013 created a local shortage of reactive power support, endangering stable grid operations for SCE in the Los Angeles Basin area. To meet this reactive power need, SCE sought approval to deploy traditional reactive power equipment at a cost of $200-$350 million, as outlined in the table below. DERs were not included in the procurement to meet this need. Had DERs with smart inverters been evaluated as part of the solution, significant reactive power capacity could have been obtained to avoid the deployment of expensive traditional equipment.

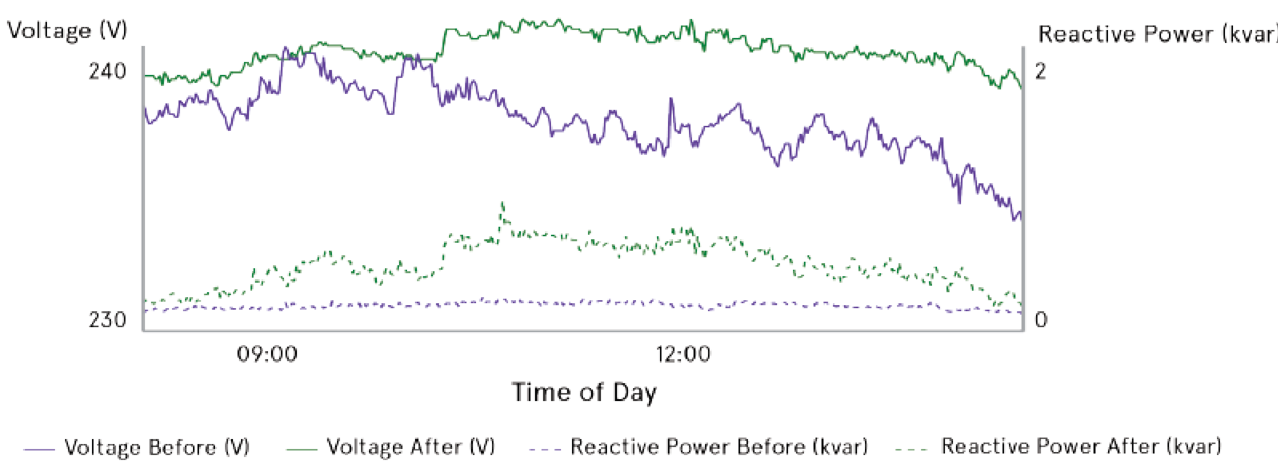
SONGS Reactive Power Replacement Projects

PROJECT	CAPACITY (MVAR)	IN-SERVICE	COST
Huntington Beach Synchronous Condensers	280	6/1/2013	$4.75M
Johanna and Santiago 220 kV Capacitor Banks	160	7/1/2013	$1.1-10M
			$10-50M
Viejo 220 kV Capacitor Banks	160	7/1/2013	$1.1-10M
			$10M
			$10-50M
Talega Area Dynamic Reactive Support	250	6/1/2015	$58-72M
South Orange County Dynamic Reactive Support	400	12/1/2017	$50-75M
Penasquitos 230 kV Synchronous Condenser	240	5/1/2017	$56-70M
Total	**1,400**		**$201-$352M**

Sources[20,21,22,23,24,25,26,27]

At the distribution level, smart inverters can provide voltage regulation and improve customer power quality, functions that are traditionally handled by distribution equipment such as capacitors, voltage regulators, and load tap changers. While the provision of reactive power may come at the expense of real power output (e.g. such as power otherwise produced by a PV system), inverter headroom either exists or can readily be incorporated into new installations to provide this service without impacting real power output. The capability of DER smart inverters to provide voltage and power quality support is currently being demonstrated in several field demonstration projects across the country. For instance, a demonstration project in partnership with an investor-owned utility is currently demonstrating the voltage support from a portfolio of roughly 150 smart inverters controlling 700kW worth of residential PV systems. The chart below depicts the dynamic reactive power delivered to support local voltage. In this instance, smart inverter support resulted in a 30% flatter voltage profile.[28]

Reactive power and voltage support from a smart inverter



Projects such as the SONGS reactive power procurement project provide recent examples where utility investment was made for reactive power capacity. These projects were used to quantify the economic benefit of DERs providing reactive power support. To do so, a corresponding $/kVAR-year value was applied to the inverter capacity assumed in the deployment scenarios to determine the value of the services offered by the DER portfolio. Note, also, that markets including NYISO, PJM, ISO-NE, MISO, and CAISO already compensate generators for capability to provide and provision of reactive power.[29]

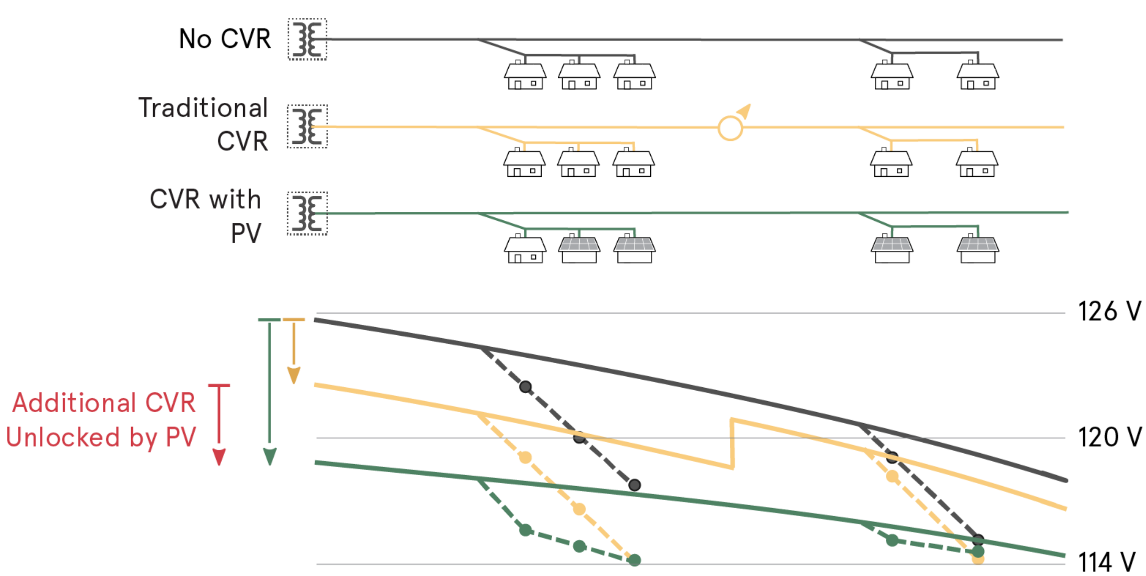
Conservation Voltage Reduction

Smart inverters can enable greater savings from utility conservation voltage reduction (CVR) programs. CVR is a demand reduction and energy efficiency technique that reduces customer service voltages in order to achieve a corresponding reduction in energy consumption. CVR programs are often implemented system-wide or on large portions of a utility's distribution grid in order to conserve energy, save customers on their energy bills, and reduce greenhouse gas emissions. CVR programs typically save up to 4% of energy consumption on any distribution circuit.[30] The utilization of smart inverters is estimated to yield another 1-3% of incremental energy consumption savings and greenhouse gas emissions reductions.

From an engineering perspective, CVR schemes aim to reduce customer voltages to the lowest allowable limit as allowed by American National Standards Institute (ANSI) standards. However, CVR programs typically only control utility-owned distribution voltage regulating equipment, changes to which affect all customers downstream of any specific device. As such, CVR benefits in practice are limited by the lowest customer voltage in any utility voltage regulation zone (often a portion of a distribution circuit), since dropping the voltage any further would violate ANSI standards for that customer.

Since smart inverters can increase or decrease the voltage at any individual location, DERs with smart inverters can be used to more granularly control customer voltages in CVR schemes. For example, if the lowest customer voltage in a utility voltage regulation zone were to be increased by, say, 1 Volt by controlling a local smart inverter, the entire voltage regulation zone could then be subsequently lowered another Volt, delivering substantially increased CVR benefits. Such an example is depicted in the image below, where the green line represents a circuit voltage profile where smart inverters support CVR. Granular control of customer voltages through smart inverters can dramatically increase CVR benefits.

DERs control voltage locally and enable CVR

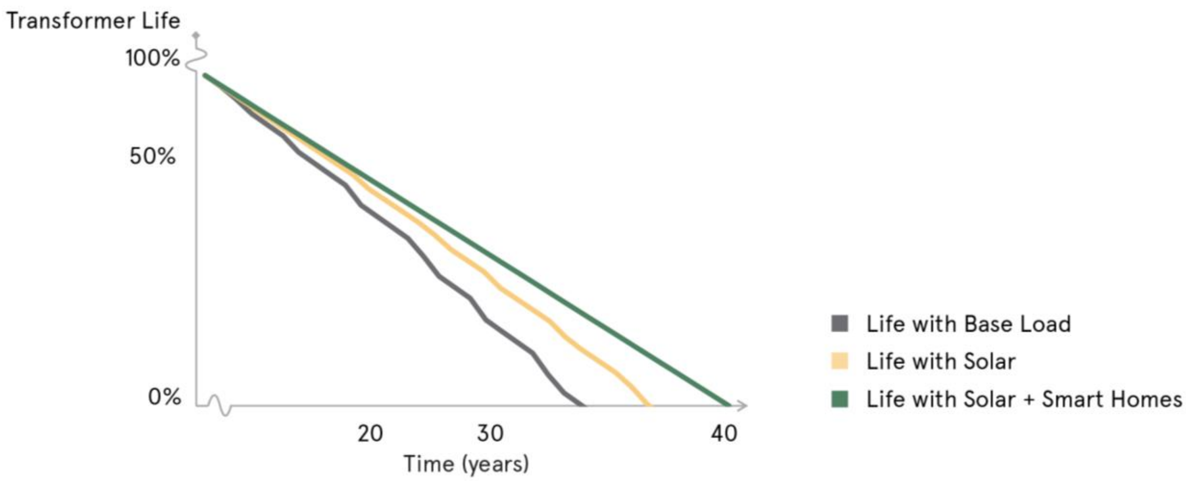


Equipment Life Extension

Either through local generation, load shifting, and/or energy efficiency, DERs reduce the net load at individual customer premises. A portfolio of optimized DERs dispersed across a distribution circuit in turn reduces the net load for all equipment along that distribution circuit. Distribution equipment, such as substation transformers, operating at reduced loading will benefit from increased equipment life and higher operational efficiency.

Distribution equipment may operate at very high loading during periods of peak demand, abnormal configuration, or emergency operation. When the nominal rating of equipment is exceeded, or overloaded, the equipment suffers from degradation and reduction in operational life. The more frequently that equipment is overloaded, the more that such degradation occurs. Furthermore, the efficiency of transformers and other grid equipment falls as they perform under increased load. The higher the overload, the larger the efficiency losses. Utilities have significant portions of their grid equipment that regularly operate in overloaded fashion. DERs' ability to reduce peak and average load on distribution equipment therefore leads to a reduction in the detrimental operation of the equipment and an increase in useful life, as shown in the following figure. The larger the peak load reduction, the larger the life extension and efficiency benefits.

Distributed Energy Resources Extend Transformer Life



To quantify these benefits, medium to large liquid-filled transformers were modeled with typical load and DER generation profiles. The magnitude of the reduced losses and resulting equipment degradation avoidance were calculated using IEEE C57.12.00-2000 standard per unit life calculation methodology.[31,32] DERs such as energy storage are able to achieve an even greater avoided cost than solar alone, as storage dispatch can more closely match the distribution peak. Quantified benefits contributing to net societal benefits calculation include the deferred equipment investment due to extended equipment life and reduced energy losses through increased efficiency.

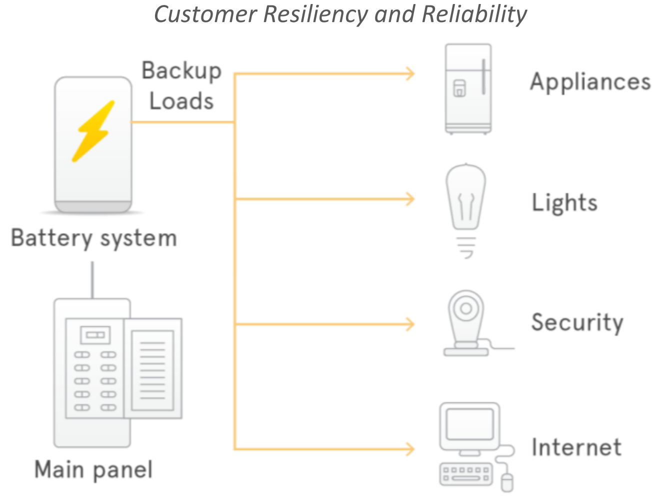
Note that non-optimized DERs can be cited as having negative impact on equipment life. While highly variable generation and load can negatively impact equipment life – such as driving increased operations of line regulators – optimized and coordinated smart inverters mitigate this potential volatility impact on equipment life.

Resiliency and Reliability

DERs such as energy storage can provide backup power to critical loads, improving customer reliability during routine outages and resiliency during major outages. The rapidly growing penetration of batteries combined with PV deployments will reduce the frequency and duration of customer outages and provide sustained power for critical devices, as depicted in the adjacent figure.

Improved reliability and resiliency has been the goal of significant utility investments, including feeder reconductoring and distribution automation programs such as fault location, isolation, and service restoration (FLISR). Battery deployments throughout the distribution system can eventually reduce utility reliability and resiliency investments. However, this analysis utilizes a conservative approach, only considering average customer savings from reduced outages and excludes avoided utility investments.

Distributed Energy Resources Improve Customer Resiliency and Reliability



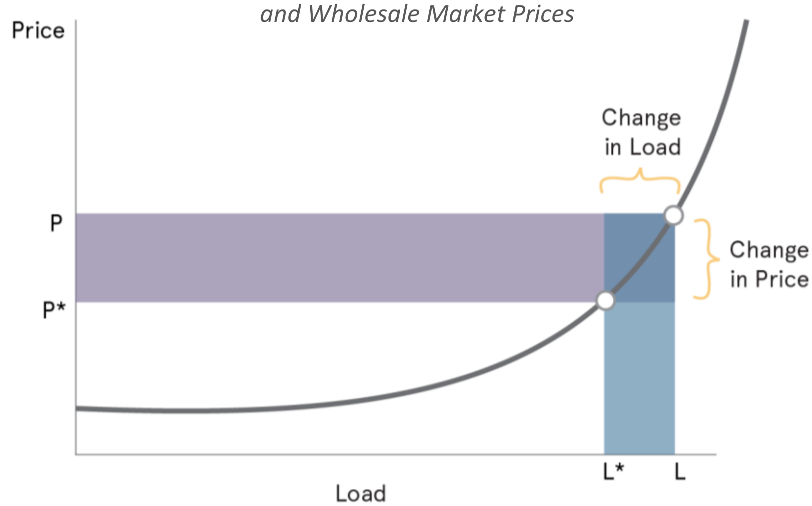
To quantify near-term reliability and resiliency benefits, the value of lost load as calculated by Lawrence Berkeley National Lab[33] was applied to the energy that could be supplied during outages. Outages were based on 2014 CPUC SAIFI statistics.

Market Price Suppression Effect

Wholesale electricity markets provide a competitive framework for electric supply to meet demand. In general, as electric demand increases market prices increase. DERs can provide value by reducing the electric demand in the market, leading to a reduction in the market clearing price for all consumers of electricity. This effect was recently validated in the U.S. Supreme Court's decision to uphold FERC Order 745, noting that operators accept demand response bids if and only if they bring down the wholesale rate by displacing higher-priced generation. Notably, the court emphasized that "when this occurs (most often in peak periods), the easing of pressure on the grid, and the avoidance of service problems, further contributes to lower charges."[34] As a behind-the-meter resource, rooftop solar impacts wholesale markets in a similar way to demand response, effectively reducing demand and thus clearing prices for all resources during solar production hours. While the CPUC Public Tool attempts to consider the avoided cost of wholesale energy prices, it does not consider the benefits of reducing wholesale market clearing prices from what they would have been in the absence of solar.

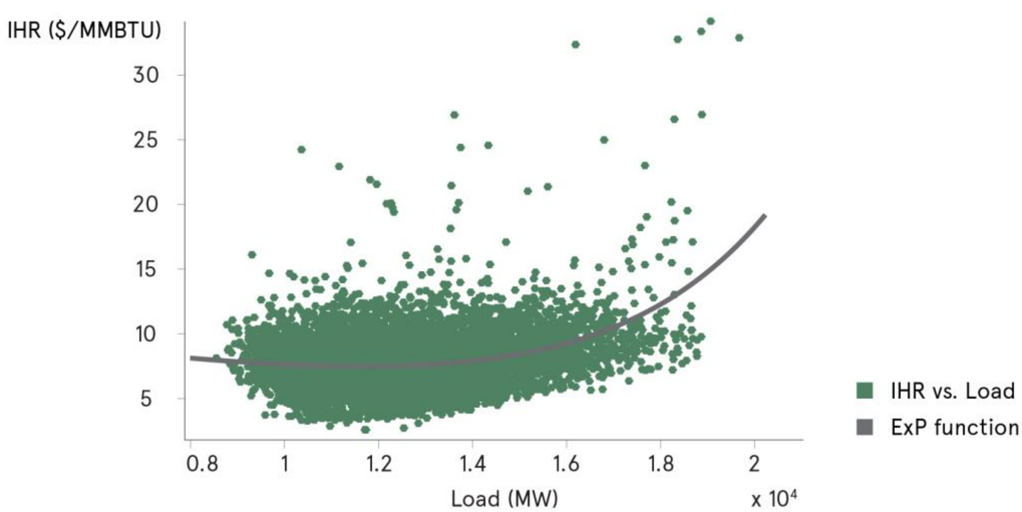
This effect is illustrated in the adjacent figure. In the presence of DERs, energy prices are at the lower "P^*" price which otherwise would have been at the higher "P" price absent the DERs. Market price suppression could then be quantified as the difference between prices multiplied by load, or $(P - P^*) * L^*$.

Relationship between Electric Demand and Wholesale Market Prices



To quantify the magnitude of cost reductions due to market price suppression, this report estimates the relationship between load and market prices based on historical data. It is important to isolate other driving factors to only capture the effect of load change on prices. One of these driving factors is natural gas prices, which directly impacts electric prices because the marginal supply resource in California is often a natural gas-fired power plant. This can be isolated by normalizing market prices over gas prices, known as Implied Heat Rate (IHR), and estimating the relationship between IHR and load, which is shown in figure below for PG&E DLAP prices and load.

Relationship between electric demand and Implied Heat Rate for PG&E



Smart energy homes equipped with energy storage are able to achieve an even greater avoided cost than distributed solar alone. Storage devices that discharge in peak demand hours with high market clearing prices can take advantage of the stronger relationship between load and price at high loads.

Results

After establishing the 2016-2020 penetration scenario and defining the methodologies for each category of avoided cost, the CPUC Public Tool was utilized to estimate the benefits of achieving the 2020 penetration scenario. For avoided cost categories the CPUC Public Tool was not able to incorporate, calculations were completed externally using common penetration and operational assumptions for each technology type. In order to be consistent with the CPUC Public Tool outputs, levelized values are expressed in annual terms in 2015 dollars below.

Annual Benefits of 2016-2020 DER Deployments

AVOIDED COST CATEGORY	PV + SMART INVERTER ($M/YEAR)	+DERs ($M/YEAR)	TOTAL ($M/YEAR)
Penetration Levels	*4.5 GW*	*90,000 Homes*	
Energy + Losses	$637	$74	$710
Generation Capacity	$91	$99	$190
Transmission Capacity	$333	$42	$375
Distribution Capacity	$187	$54	$241
Ancillary Services	$6	$1	$7
Renewable Energy Compliance	$199	$23	$221
Societal Benefits	$371	$43	$414
Voltage and Power Quality	$91	$7	$99
Conservation Voltage Reduction	$34	$4	$38
Equipment Life Extension	$31	$4	$36
Reliability & Resiliency	$0	$8	$8
Market Price Suppression	$163	$19	$182
Total Benefits	**$2,143**	**$378**	**$2,521**

Previous assessments of high penetration DERs have replicated existing methodologies that have often been applied to passive assets like energy efficiency; however, these approaches fail to recognize the potential value of advanced DERs that will be deployed during the 2016-2020 timeframe. When a more comprehensive suite of benefits that could be generated by DERs today is considered, total benefits of the 2016-2020 DER portfolio in California exceeds $2.5 billion per year.

C. The Costs of Distributed Energy Resources

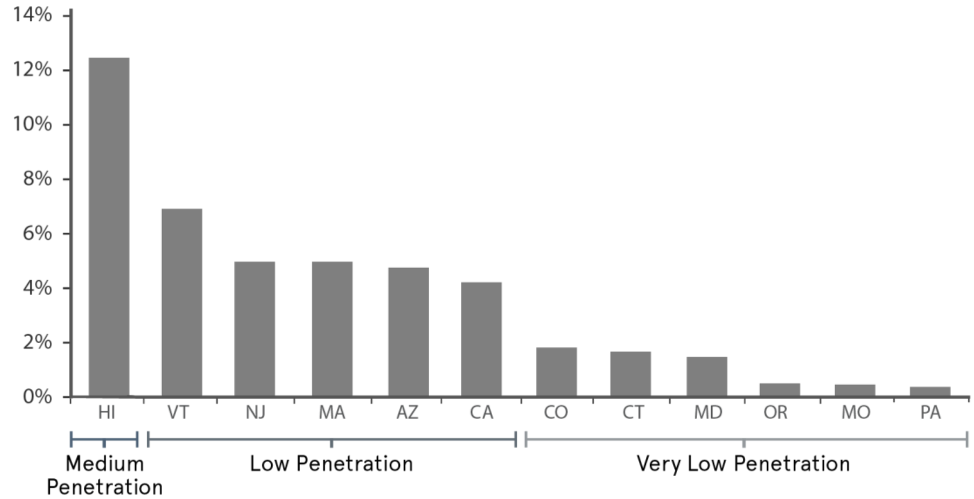
As presented above, distributed resources offer significant ratepayer benefits; however, these benefits are not available without incurring incremental costs to enable their deployment. In order to quantify the net societal benefit of DERs, these costs must be subtracted from the benefits. Costs for distributed energy resources include integration at the distribution and bulk system levels, utility program management, and customer equipment.

Distribution Integration Costs

DERs are a critical new asset class being deployed on the distribution grid which must be proactively planned for and integrated with existing assets. This integration process will sometimes require unavoidable additional investments. However, it is essential to separate incremental DER integration costs from *business as usual* utility investments. Recent utility funding requests for DER integration have included costs above those needed to successfully integrate DERs. This subsection will explore typical DER integration costs and evaluate the validity of each type.

While new DER integration rules of thumb and planning guidelines are emerging,[35] no established approach exists for identifying DER integration investments or estimating their cost. It is clear, however, that integration efforts and costs vary by DER penetration level. Generally, lower DER penetration requires fewer integration investments, while higher penetration may lead to increased investment. As depicted in the following chart, NEM PV penetration levels vary across the U.S.[36] Most states have *very low* (<5%) penetrations, while only Hawaii experiences *medium* (10-20%) penetration. California exhibits *low* (5-10%) penetration overall, although individual circuits may experience much higher penetration.

NEM Solar Capacity as a Percentage of Total System Peak



For this analysis, DER integration costs were developed from estimates submitted by California utilities to the CPUC as part of their Distribution Resource Planning (DRP) filings. This analysis incorporates the specific cost categories and figures from Southern California Edison's filing, since this filing alone included specific cost estimates. In assessing these costs, each proposed investment was reviewed to determine whether it was a required incremental cost resulting from the integration of DERs. If so, it should indeed be included in the cost/benefit calculation. If the investment (or a portion thereof) was determined to be a component of utility *busines as usual* operations, such investment was not included in the analysis.

In order to determine whether a proposed utility investment is required, the following *threshold question* was asked:

- *Would these costs be incurred even in the absence of DER adoption?*

If the costs would be incurred regardless of DER adoption, or if the utility had previously requested regulatory approval for the investment but justified the investment via a program unrelated to DER adoption, then the costs should not be classified as DER integration costs. For example, if a utility had previously requested approval to upgrade (i.e. cutover) 4kV circuits to a higher voltage in order to increase capacity and reliability before DERs were prevalent, yet now associates the upgrade costs to DERs, then the investment should not be attributed to DER integration. This threshold analysis eliminates from consideration or reduces some of the proposed utility integration costs.

Of the remaining costs, each was further assessed by asking the following set of *screening questions*:

- Do more cost effective mitigation measures exist for the proposed investment? Can advanced DER functionalities (e.g. volt/VAR support) mitigate or eliminate the need for the investment?
- Are costs relevant for the forecasted DER penetration levels, or only for much higher penetrations?
- Do stated costs reflect realistic cost figures, or do they reflect inflated estimates?

Several utility integration investments are proposed to mitigate an integration challenge where more cost effective solutions exist. For example, voltage-related concerns due to PV variability are often used to justify replacement of capacitor banks on distribution feeders. However, the use of embedded voltage and reactive power capabilities in smart inverters make the deployment of new capacitor banks redundant and overly expensive in most instances. Furthermore, while some proposed costs may be relevant for high penetrations of DERs – such as bi-directional relays to deal with reverse power flows – these investments may not be necessary at low penetration levels.

The following table presents the DER integration investment categories as identified in SCE's DRP filing according to its Scenario 3 forecast for DER growth in California. SCE's integration costs were scaled up in order to estimate total distribution integration costs for all California utilities; therefore, the table represents total California distribution integration costs over 2016-2020. For each investment, applicability to DER integration is assessed using the threshold and screening questions discussed above, resulting in a quantification of costs that are directly "Applicable to DERs". An overview of the assessment of each high-level integration category is provided in the table, with more detailed technical discussion of each investment type and assessment rationale offered in the Appendix. This cost quantification is necessarily high-level due to the lack of details available for each investment type. As such, more specific assessment is necessary in order to evaluate integration investment plans. This exercise identifies 25% of SCE's DER integration costs, or $1,450 million (or levelized to $189 million annually[37]), as truly applicable to DER integration, which is the number utilized in the cost/benefit analysis in this paper.

CATEGORY	INVESTMENTS	UTILITY COST CLAIM ($M)	APPLICABLE TO DERs (%)
Distribution Automation	Automated switches w/enhanced telemetry, remote fault indicators	$710	0%
Substation Automation	Substation automation, modern protection relays	$691	30%
Communication Systems	Field area network, fiber optic network	$888	0%
Grid Reinforcement	Conductor upgrades to a larger size, conversion of circuits to higher voltage	$1,070	50%
Technology Platforms and Applications	Grid analytics platform/applications, long-term planning tool set, distribution circuit modeling tool, interconnection application processing, DRP data sharing portal, grid/DER management system, system architecture and cyber security, distribution Volt/VAR optimization	$2,337	30%
Total Distribution Integration Costs		**$5,697**	**25% (1,450)**

Bulk System Integration Costs

Integration of variable resources with the bulk power grid is expected to result in an increase in variable operating costs associated with the way the generation fleet is used to accommodate the variability. To quantify this cost, $/MWh values quantifying this cost for a 33% renewable portfolio standard were scaled per calculations adopted by the California PUC.[38]

Utility Program Management Costs

To estimate the incremental utility program costs associated with DER adoption, the default inputs within the Public Tool were used, which include upfront installation and metering costs, as well as incremental billing costs. All told, these costs amounted to $26 million per year based on the level of adoption in the TASC base case scenario.

Customer Equipment Costs

The costs of DERs themselves must be considered, including the cost of equipment, labor, and financing. For solar, CPUC Energy Division staff's reference case solar price forecast is used to determine the cost of deployed equipment in the 2016-2020 timeframe, factoring in the December 2015 extension of the Federal Investment Tax Credit. For storage, the price forecast was based on Navigant Research's projections;[39] for controllable thermostats, current vendor prices were used.

Based on these forecasts, deployments forecasted for the 2016-2020 timeframe yielded a blended average adoption cost of the installed base of $3.86/W for the 2016-2020 timeframe, or $2.70/W after reflecting the 30% Federal Investment Tax Credit (ITC). In absolute terms, the total cost of adoption to Californians translates to $12.1 billion (nominal) for 4.5GW of rooftop solar. For co-located storage and load control, total investment to meet adoption forecasts totals $259 million.

Results

Societal net benefits calculations require a comprehensive consideration of costs that society bears as a result of attaining the specified 2020 penetration levels, including the costs of administering customer programs, grid integration costs needed to accommodate new assets, and the cost of the assets themselves, which are borne by customers. In the table below, each category is quantified, totalling $1.1 billion per year.

CATEGORY	PV + SMART INVERTER ($M/YEAR)	+DERs ($M/YEAR)	TOTAL ($M/YEAR)
Penetration Levels	*4.5 GW*	*90,000 Homes*	
Utility Program Management Costs	$24	$3	$26
Integration Costs (Distribution + Bulk)	$170	$20	$189
Customer Equipment Costs	$770	$119	$889
Total Costs	**$964**	**$141**	**$1,105**

D. Quantifying Net Benefits

In this section, we complete EPRI's Cost/Benefit analysis by comparing benefits and costs of DERs during the 2016-2020 deployment timeframe. For consistent comparisons, levelized costs and benefits are based on the year 2020, with all benefits and costs values translated to 2015 dollars.[40]

Establishing a common DER penetration scenario and converting all benefits and costs to net present value terms allows simple summation of each category to provide indicative societal net benefit, suggesting a significant societal value for widespread DER adoption. In total, the benefits of the analyzed scenario are $2.5 billion per year, compared to costs of $1.1 billion per year, resulting in a net societal benefit to Californians of $1.4 billion per year by 2020.

Results of EPRI Societal Net Benefit Test

	CATEGORY	PV+SMART INVERTER ($M/YEAR)	+DERS ($M/YEAR)	TOTAL ($M/YEAR)
Benefits	Energy + Losses	$637	$74	$710
	Generation Capacity	$91	$99	$190
	Distribution Capacity	$333	$42	$375
	Transmission Capacity	$187	$54	$241
	Ancillary Services	$6	$1	$7
	Renewable Energy Compliance	$199	$23	$221
	Voltage and Power Quality	$91	$7	$99
	Conservation Voltage Reduction	$34	$4	$38
	Equipment Life Extension	$31	$4	$36
	Reliability & Resiliency	$0	$8	$8
	Market Price Suppression	$163	$19	$182
	Societal Benefits	$371	$43	$414
	Total Benefits	**$2,143**	**$378**	**$2,521**
Costs	Program Costs	$24	$3	$26
	Integration Costs	$170	$20	$189
	Equipment Costs	$770	$119	$889
	Total Costs	**$964**	**$141**	**$1,105**
	Total Net Benefits			**$1,416**

E. Case Study: PG&E's Planned Distribution Projects in 2017 General Rate Case

In the previous section, categories of avoided costs were described and the corresponding values were quantified for the state of California. In this section, the same methodology is applied to PG&E's planned distribution projects from its most recent PG&E 2017 General Rate Case filing from September 2015.

Every three years, California utilities seek approval to recover expenses and investments, including a target profit level, that are deemed necessary for the prudent provision of utility services. For perspective, half of customer's utility payments were driven by the "wires" component of the electric grid in 2014[41] and California's investor owned utilities are expected to add $143 billion of new capital investment into their distribution rate bases through 2050.[42]

Despite the significant size of this avoided cost category, DERs have historically been considered passive assets having little potential on the "wires" side of the business. While not all distribution investment can be avoided by DERs, some of the currently-planned projects are being implemented to accommodate demand growth and replacement of aging assets; these projects could instead be deferred or avoided by DERs. While the CPUC Public Tool uses a generalized treatment of distribution capacity avoided costs to estimate the potential value of deferrals across utilities, more specific values are used in this section sourced from publicly available documents.

The table below summarizes the large capacity-related distribution projects detailed in PG&E's General Rate Case. PG&E seeks approval of $353 million for these distribution system investments.[43] When this $353 million PG&E capital investment is adjusted to factor in the ratepayer perspective – which includes the lifetime cost of the utility's target profit level and recovery of costs related to operations and maintenance, depreciation, interest and taxes from ratepayers – the net present societal cost to PG&E ratepayers of these distribution capacity projects is approximately $586 million.[44] This $586 million cost to ratepayers adds over 1GW of conventional distribution capacity but addresses only 256 MW of near-term capacity deficiencies on PG&E's distribution system when deployed.

Summary of PG&E Electric Distribution Capacity Request – 2017 GRC[45]

Net Present Ratepayer Cost of Capital Investment ($M)[46]	$586
Near-term GRC Forecast Deficiency Addressed (MW)	256

Based on this societal cost, we consider the net benefits of an alternative, DER-centric solution, which relies on solar with smart inverters, energy storage and controllable thermostats. Due to lack of sufficient detail from PG&E's General Rate Case regarding the operational profiles of the electric distribution capacity projects in question, a simplifying assumption of 75% is used for the DER portfolio's distribution load carrying capacity ratio, which is based on the CPUC's Public Tool default peak capacity allocation factors (PCAF) for PG&E's distribution planning areas. This load carrying capacity ratio reflects capabilities based on customer adoptions with a storage sizing ratio of 2 kWh of energy storage for every 1 kW of PV capacity, or approximately 10 kWh of energy storage for a customer with 5kW of solar installed, as well as a controllable thermostat.

In order to accurately compare the DER solution, the full lifetime cost of the DER solution is considered, which includes the costs of additional DERs that would be needed to accommodate load growth over the lifetime of the conventional solution – assumed to be 25 years. This DER solution deployment schedule, which continuously addresses incremental capacity needs on the grid, contrasts with the traditional, bulky solution deployment schedule, which requires a large upfront investment for capacity to address a small, incremental near-term need. While a DER solution delivers sufficient capacity in each year to provide comparable levels of grid services, deployments occur steadily over time rather than in one upfront investment.

This approach highlights one of the key potential benefits of utilizing a DER solution over a traditional, bulky grid asset: DERs can be flexibly deployed in small bundles over time, a benefit that is further explored in Section IV on the benefits of transitioning to more integrated distribution planning.

Using these assumptions, the previous state-wide methodology is applied to DERs avoiding PG&E's planned distribution capacity projects, but two conservative assumptions are made. First, the scope of benefits is limited to a subset of avoided cost categories that would be directly considered by utility planners today for these types of projects. Whereas conventional equipment used to meet distribution capacity projects are generally unidimensional resources providing a single source of value – distribution capacity – DERs provide multiple sources of value. Second, we base our calculations on PG&E's lower avoided cost values,[46] rather than our own, to demonstrate that there are net benefits even under a conservative scenario.

In addition to avoiding the ratepayer cost of $586 million for planned distribution capacity projects, the DERs deployed to avoid PG&E's distribution capacity projects also avoid $946 million in energy purchases and $79 million and $99 million in generation capacity and avoided renewable energy credit purchases, respectively, totaling $1,709 million in benefits. On the cost side, program costs, integration costs and equipment costs for the associated DERs total to $1,605 million, resulting in a net present value to PG&E ratepayers of $104 million. This net benefit result is particularly notable given the limited scope of benefits considered in this case study and the reliance on PG&E's lower avoided cost values.

Net Benefit of DER Solutions to PG&E Electric Distribution Capacity Request – 2017 GRC
(Calculations Based on PG&E Cost and Benefit Assumptions)

TYPE	CATEGORY	SOURCE	NPV (2015 $M)
Benefits	Energy + Losses	PG&E NEM Successor Filing [48]	$946
	Generation Capacity[49]	PG&E NEM Successor Filing	$79
	Distribution Capacity	PG&E 2017 General Rate Case	$586
	Transmission Capacity	Not Included	-
	Ancillary Services	Not Included	-
	Renewable Energy Compliance	PG&E NEM Successor Filing	$99
	Voltage and Power Quality	Not Included	-
	Conservation Voltage Reduction	Not Included	-
	Equipment Life Extension	Not Included	-
	Reliability & Resiliency	Not Included	-
	Market Price Suppression	Not Included	-
	Societal Benefits	Not Included	-
	Total Benefits		**$1,709**
Costs	Program Costs	PG&E Nem Successor Filing	$55
	Integration Costs	SCE DRP with SolarCity Revisions	$363
	Equipment Costs	PG&E NEM Successor Filing	$1,188
	Total Costs		**$1,605**
	Total Net Benefits		**$104**

In this section, the data available to third-parties around distribution capacity projects from the most recent California Phase I General Rate Case (PG&E's 2017 GRC filing) was used to explore the potential benefits of leveraging DERs to avoid conventional distribution capacity-related investments. Calculations were performed based on PG&E's own avoided cost assumptions from NEM Successor Tariff filings and General Rate Case filings. Results indicate that deploying DER solutions in lieu of PG&E's planned distribution capacity expansion projects in its 2017 GRC could yield net benefits, even looking only at the energy, capacity, and renewable energy compliance values of the DER solutions. While not preferred, simplified assumptions were used to fill missing sources of information and data (e.g. distribution peak capacity allocation factors and forecasted load growth) where necessary. That such simplifying assumptions are necessary highlights the need for additional data sharing on specific infrastructure projects in order to assess the potential of DERs to offset these investments.

III. Utility Regulatory Incentives Must Change in Order to Capture DER Benefits

Section II demonstrated how California could realize an additional $1.4 billion per year by 2020 in net benefits from the deployment of new DERs during the 2016-2020 timeframe. This state-wide methodology was then applied to the planned distribution capacity projects for California's most recent GRC request, showing how the deployment of DERs in lieu of planned distribution capacity expansion projects in PG&E's next rate case could save customers over $100 million.

Despite this potential value from embracing a distribution-centric grid, utilities face institutional barriers to realizing these benefits. Reducing the size of a utility's ratebase – its wires-related investments – cuts directly into shareholder profits. Expecting utilities to proactively integrate DERs into grid planning, when doing so has the potential to adversely impact shareholder earnings, is a structurally flawed approach. It will be impossible to completely capture the potential benefits of DERs until the grid planner's financial conflict with the deployment of DERs is neutralized.

Incentive Barriers

Realigning the incentives of the grid planner to solely focus on delivering a safe, reliable and affordable grid, regardless of the ownership and service models that materialize in the market, is a necessary first step to realize the potential of DERs. There are two fundamental paths forward to address this conflict of interest.

The first path towards realizing this objective would be to separate the role of distribution planning, sourcing, and operations from the role of distribution asset owner, similar to the evolution of Independent System Operators (ISOs) and Regional Transmission Operators (RTO) at the bulk system level. FERC's decree to create independent operators in Order 2000 was driven by the observation that the lack of independent operation of the bulk power system enabled transmission owners to continue discriminatory operation of their systems to favor their own affiliates and further their own interests.[47]

However, while an independent distribution system operator (IDSO) is an appealing governance model, some state regulators may choose a second path for addressing the utility conflict of incentives: maintaining the utilities' traditional role in planning and operating the distribution grid, while neutralizing the misalignment by changing utility incentives. Given the near-term focus in many states on retaining the utility's current role in grid planning and operation, this paper chooses to focus on this path and proposes a model that ensures the utility incentive against non-utility owned assets is neutralized.

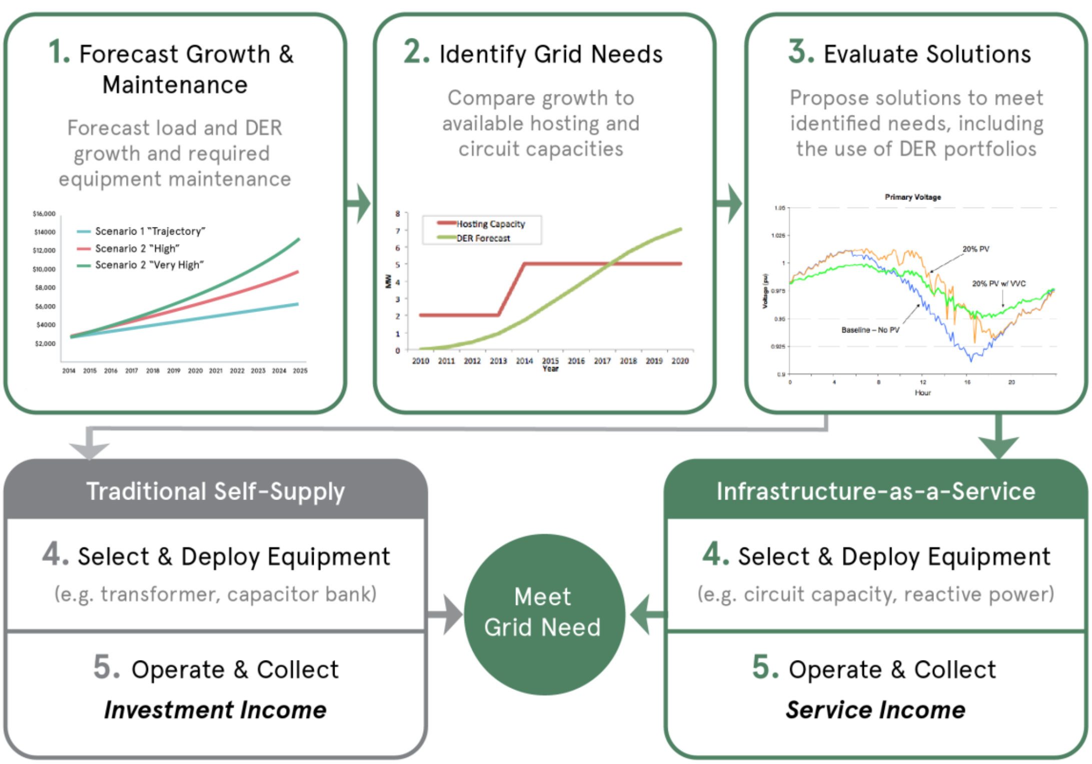
Proposed Solution

In order to ensure least cost/best fit distribution investments in states without an IDSO, this paper proposes the creation of a new utility incentive model, *Infrastructure-as-a-Service,* which would neutralize the utility incentive to deploy utility-owned infrastructure in lieu of more cost-effective third-party options. This model would enable utility shareholders to derive income from third-party grid services, mitigating the financial impact that may bias utility decision-making. Such a model would help ensure that utilities take full advantage of DER readily being adopted by customers.

Infrastructure-as-a-Service

Infrastructure-as-a-Service is a regulatory mechanism that would modify the incentives faced by utilities when sourcing solutions to meet grid needs. This new mechanism would allow utilities to earn income, or a rate of return, from the successful provision of grid services from non-utility owned DERs. Infrastructure-as-a-Service facilitates the least cost/best fit development of distribution grids by creating competitive pathways for DERs to defer or replace conventional grid investments, while maintaining equal or superior levels of safety, reliability, resiliency, power quality, and customer satisfaction. As the figure below shows, the three primary steps of a utility distribution planning process (forecast, identify needs and evaluate solutions) remain identical to the current process, followed by the infrastructure-as-a-Service mechanism's enhancements to sourcing in steps four (select and deploy) and five (operate and collect).[48]

Utility Planning and Sourcing Utilizing Infrastructure-as-a-Service Model



Under the proposed approach, after evaluating all feasible technical solutions for a particular grid need, including alternative grid solutions derived from DER portfolios, Infrastructure-as-a-Service would empower distribution planners to select and deploy third-party assets that address the specified need *if* more cost-effective for ratepayers than conventional solutions. Importantly, Infrastructure-as-a-Service would create an opportunity for utilities to operate and collect streams of service income, or a rate of return, based on the successful deployment of competitively sourced third-party solutions. This service income provides fair compensation for effective administration of third-party contracts that enable alternative resources to deliver grid services, and helps mitigate the structural bias towards utility-owned infrastructure that currently exists under distribution "cost plus" regulation. Note that other mechanisms attempting to achieve a similar utility indifference to DER solutions have been proposed, such as the modified clawback mechanism being discussed in New York.[49] While the clawback mechanism offers the potential to reduce the financial disincentive that utilities face in utilizing DERs, the potential utility upside may be small as compared to the lost opportunity and insufficient to neutralize the utility disincentive. This downside to the clawback mechanism may be overcome via the infrastructure-as-a-service mechanism.

Distribution Loading Order

Neutralizing the utility disincentive to utilizing DERs is critical but not sufficient to drive transformation in distribution planning. New incentives may be ignored in practice without corresponding changes to long-established and familiar utility processes that have sourced only self-supplied solutions to date. The adoption of a Distribution Loading Order[50] would borrow an existing concept from bulk system procurement policy in California, which prioritizes procurement of preferred resources, including energy efficiency, demand response, and renewable energy, ahead of fossil fuel-based sources. In the distribution context, a Distribution Loading Order prioritizes the utilization of flexible DER portfolios over traditional utility infrastructure, when such portfolios are cost-effective and able to meet grid needs. The table below depicts the types of resources that would be prioritized over traditional investments in such a policy.

Distribution Loading Order: Sourcing Solutions

PRIORITY	RESOURCE TYPE	RESOURCE EXAMPLES
1	Distributed Energy Resources	Energy efficiency, controllable loads/demand response, renewable generation, advanced inverters, energy storage, electric vehicles
2	Conventional Distribution Infrastructure	Transformers, reconducturing, capacitors, voltage regulators, sectionalizers

In concert with a mechanism like *Infrastructure-as-a-Service*, a Distribution Loading Order provides the procedural framework for evaluating distribution solutions in order to ensure grid planning is consistent with longer term policy objectives that support environmental, reliability, and customer choice goals. Importantly, a Distribution Loading Order would ensure that DER solutions are properly incorporated into grid planning. However, utilities would always maintain the authority to select and deploy a suitable portfolio of solutions, including conventional solutions when more appropriate, to ensure reliability. For these conventional investments, utilities would continue to earn an authorized rate of return.

Benefits of Infrastructure as a Service

Creating a pathway for DERs to offer grid services in lieu of utility infrastructure investment would be beneficial for utility ratepayers for a variety of reasons.

1. Saves ratepayers money: Allowing full and fair consideration of DER solutions equips grid planners with a broader suite of tools to meet grid needs, resulting in higher infrastructure utilization and lower customer electricity bills.
2. Promotes competition: Expanding the set of suppliers that are eligible to offer distribution solutions unleashes the power of markets to benefit ratepayers. Well-designed competitive markets can deliver superior solutions that are more affordable than those resulting from a self-supply "cost plus" planning model.
3. Increased flexibility and sources the best solution: Sourcing mechanisms that can deliver resources with new desirable characteristics (e.g. granular sizing, fast lead-times, flexible operational traits) into the distribution planners' toolbox creates no-regrets flexibility. And by rendering a utility neutral to the choice of ownership structure, the planner can focus on the singular objective of delivering the least-cost, best-fit solution.
4. Encourages innovation: Providing clear market opportunities for third-party solutions promotes product and service innovation, putting the collective innovation capabilities of all market participants and customers to work.

5. Engages customers: Utilizing DERs to provide grid services increases the capability and willingness of individual customers to actively manage their energy profiles. Ultimately, a neutral decision model like Infrastructure-as-a-Service will help foster the transition from passive ratepayers to proactive customers.

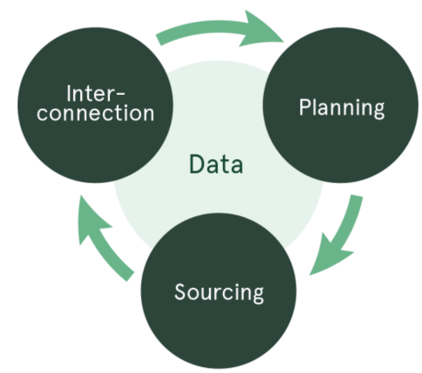
The CPUC recently enhanced the 2016 scope for its Distribution Resource Plan proceeding to formally consider the utility role, business models, and financial interest with respect to DER deployment.[51] Infrastructure-as-a-service is one mechanism to consider that would reduce the conflict of interest towards third-party services inherent in the utility incentive model today. Alternative efforts, such as creating greater functional independence between ownership and operations, as in an IDSO model, should also be explored. Irrespective of the mechanism, an effort to neutralize the utility decision model is needed to ensure that DERs are fully utilized and valued for grid services.

IV. Grid Planning Must be Modernized in Order to Capture DER Benefits

A second structural impediment to fully realizing DER benefits is the current grid planning approach, which biases grid design toward traditional infrastructure rather than distributed alternatives, even if distributed solutions better meet grid needs. Outdated planning approaches rely on static assumptions about DER capabilities and focus primarily on mitigating potential DER integration challenges, rather than proactively harnessing these flexible assets.

A. Adopt Integrated Distribution Planning

Grid planning can be modernized by utilizing an approach to meeting grid needs while at the same time expanding customer choice to utilize DERs to manage their own energy. We call this holistic process *Integrated Distribution Planning.*



Integrated Distribution Planning encourages the incorporation of DERs into every aspect of grid planning. The framework, as depicted in the adjacent figure, expedites DER *interconnections*, integrates DERs into grid *planning*, *sources* DER portfolios to meet grid needs, and ensures *data* transparency for key planning and grid information. Ultimately, the approach reduces overall system costs, increases grid reliability and resiliency, and fosters customer engagement.

If grid planning decisions are made before consideration of customers' decisions to adopt DERs, – which is frequently the case today – grid investments will underutilize the potential of DERs to provide grid services, ultimately resulting in lower overall system utilization and higher societal costs of the collective grid assets. In contrast, prudent planners who proactively plan for customer adoption of DERs may avoid making unnecessary and redundant grid investments, while also enabling the use of customer DERs to meet additional grid needs. Ultimately, planning processes must ensure that DERs are effectively counted on by grid planners and leveraged by grid operators. For more details on integrated distribution planning, see the "Integrated Distribution Planning" white paper overviewing the framework at www.solarcity.com/gridx.

B. Grid Planning Data Must be Transparent and Accessible

The first step in grid planning is to identify the underlying grid needs. As discussed throughout this paper, the use of alternative solutions such as DERs should be included in the portfolio of solutions that are considered to meet these grid needs. While utilities could ostensibly assess these alternative solutions within their existing process, opening up the planning process by sharing the underlying grid data would drive increased competition and innovation in both assessing and meeting grid needs. Any concerns from sharing such data – such as customer privacy, security, data quality, and qualified access – can be mitigated through data sharing practices already common in other industries. In fact, stakeholder engagement and access to planning data is already a central tenet in electric transmission planning across the country. The challenges of ushering a new industry norm of data transparency are far outweighed by the potential that broader data access can drive in increased stakeholder engagement and industry competition.

Data transparency efforts should first focus on communicating the exhaustive list of grid needs that utilities already identify in their planning process. While utilities may claim that such needs are already communicated within general rate cases, the information contained in those filings are incomplete. A standard set of comprehensive data should be shared about each grid need and planned investment so that stakeholders can proactively propose and develop innovative solutions to those needs. This proactive data access broadens the set of innovative solutions made available to utilities and guards against an insular approach to deploying grid investments. The table below is an initial set of minimally-required data to foster adequate stakeholder engagement in regards to specific, utility-identified grid needs.

Data to Foster Engagement in Grid Needs and Planned Investments

DATA NEED	DESCRIPTION
Grid Need Type	The type of grid need (e.g. capacity, reactive power, voltage, reliability, resiliency, spinning/non-spinning reserves, frequency response)
Location	The geographic (e.g. GPS, address) and the system location (e.g. planning area, substation, feeder, feeder node) of the grid need
Scale of Deficiency	The scale of the grid need (e.g. MW, kVAR, CAIDI/SAIDI deficiency)
Planned Investment	The traditional investment to be deployed in the absence of an alternative solution (e.g. 40 MVA transformer, 12kV reconductor, line recloser, line regulator)
Reserve Margin	Additional capacity embedded within the planned investment to provide buffer for contingency scenarios (e.g. 20% margin above expected deficiency embedded within equipment ratings to ensure available capacity during contingency scenarios)
Historical Data	Time series data used to inform identification of grid need (e.g. loading data, voltage profile, loading versus equipment ratings, etc.)
Forecast Data	Time series data used to inform identification of grid need and specification of planned investment (e.g. loading, voltage, and reliability data). Forecast to include prompt year deficiency (i.e. near-term deficiency driver), as well as long-term forecast (i.e. long-term deficiency driver)
Expected Forecast Error	Historical data that includes forecasts relative to actual demands for relevant grid need type in similar projects. Data to be used to evaluate uncertainty of needs and corresponding value of resources with greater optionality (e.g. lead times, sizing, etc.)

While data on specific utility-identified grid needs is critical to assessing innovative solutions in place of traditional investments, underlying grid data should also be made available to foster broader engagement in grid design and operations. Access to underlying grid data allows third parties to improve grid design and operation by proactively identifying and developing solutions to meet grid needs, even before they are identified by utilities. The following data should be made available and kept current by utilities in order to encourage broad engagement in grid design.

Data to Foster Engagement in General Grid Design and Optimization

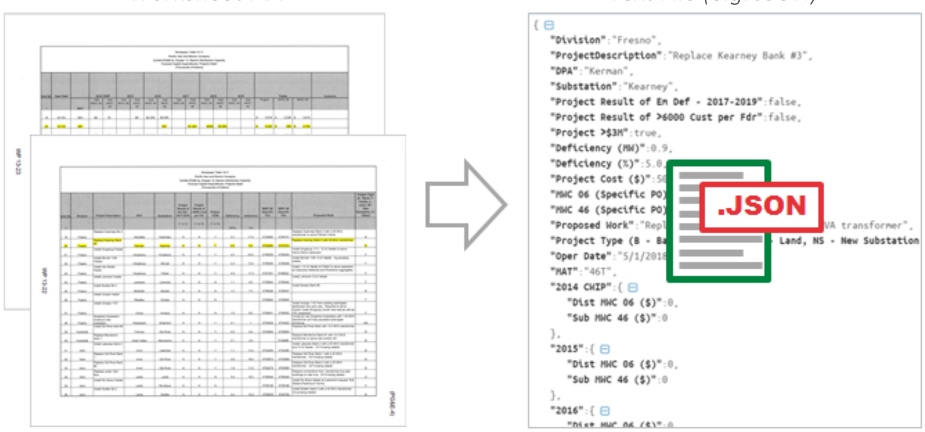
DATA NEED	DESCRIPTION
Circuit Model	The information required to model the behavior of the grid at the location of grid need.
Circuit Loading	Annual loading and voltage data for feeder and SCADA line equipment (15 min or hourly), as well as forecasted growth
Circuit DER	Installed DER capacity and forecasted growth by circuit
Circuit Voltage	SCADA voltage profile data (e.g. representative voltage profiles)
Circuit Reliability	Reliability statistics by circuit (e.g. CAIDI, SAIFI, SAIDI, CEMI)
Circuit Resiliency	Number and configuration of circuit supply feeds (used as a proxy for resiliency)
Equipment Ratings, Settings, and Expected Life	The current and planned equipment ratings, relevant settings (e.g. protection, voltage regulation, etc.), and expected remaining life.
Area Served by Equipment	The geographic area that is served by the equipment in order to identify assets which could be used to address the grid need. This may take the form of a GIS polygon.

Share Standardized, Machine-Readable Data Sets

Data that *is* made available on grid needs and planned investments is rarely provided in an accessible format. Often, information is provided in the form of photocopied images of spreadsheet tables within utility GRC filings, hardly a format the enables streamlined analysis. This data communication approach requires stakeholders to manually recreate entire data sets into electronic version in order to carry out any meaningful analysis, a time-intensive and needless exercise. Other potential stakeholders never attempt to engage due to the barrier of data access.

The use of standard, machine-readable data formats is prevalent in many industries and within the utility industry itself; organizations like the Energy Information Agency (EIA) foster such broad access to electronic, standardized data sets. Distribution grid needs and planned investments should follow suit. To illustrate a potential path forward, below is an example of traditional grid capacity needs and corresponding capacity investments as communicated via PG&E's 2017 GRC Phase 1 filing; the image of the text file on the right shows how those same grid needs and planned investments could be translated into a machine-readable format.

General Rate Case Worksheet PDF *Standard Format Text File (e.g. JSON)*



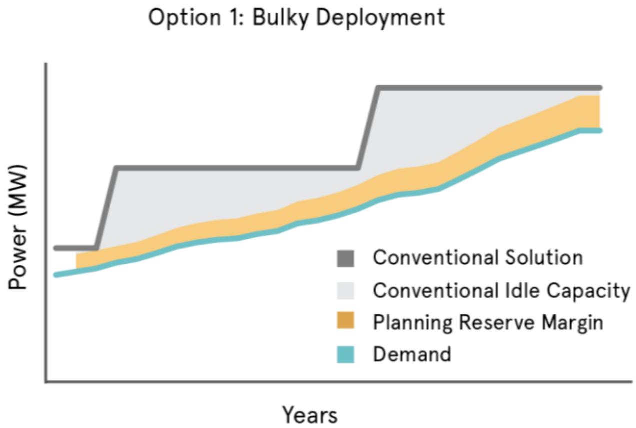
C. Benefits of Integrated Distribution Planning

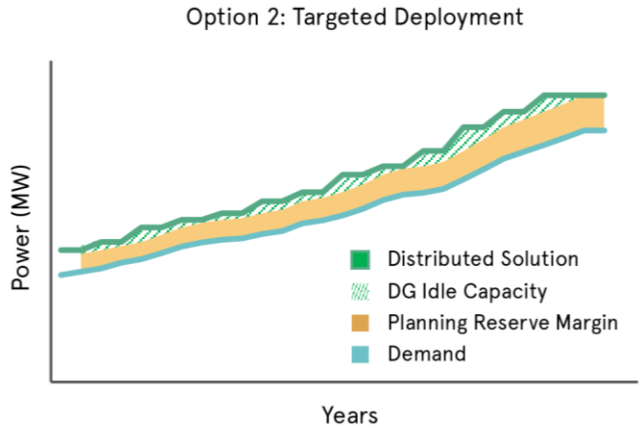
Opening the door to DER solutions in grid planning provides the obvious benefit of a new suite of technological options for grid planners. In some cases, DERs may simply be lower cost on a $/kW basis or more effective at meeting the identified grid need than the conventional solution, making them an obvious choice. DERs, however, also offer an advantage over convertional options due to their targeted and flexible nature, which fundamentally changes the paradigm of grid planning.

Status quo grid planning relies on deploying bulky, traditional infrastructure solutions to address forecasts of incremental, near-term grid needs. In many cases, conventional solutions are 15X larger than the near-term grid need that is driving the actual deployment of the infrastructure.[52] This fundamental reality of grid planning creates two major opportunities for DERs to deliver better value to ratepayers than conventional solutions: 1) utilizing small and targeted solutions, and 2) utilizing the flexibility of DER portfolios.

Value of Small & Targeted Solutions in Modern Distribution Planning

The first source of value is the result of more incremental and targeted investment, which captures the benefit of time value of money. Bulky utility solutions with long equipment lifetimes present a lumpiness challenge for planners. Needs for new resources are driven at the margin, but the available solutions are only cost-effecive when sized to match their long lifetimes, often resulting in low lifetime utilization rates. The significantly smaller building blocks that modern DERs offer planners effectively overcome this historical problem. The figures below compare the deployment timeline of a traditional bulky solution installed to meet demand growth long in the future, relative to a targeted DER solution deployed in small batches to meet continuous demand growth, and the corresponding expectation of idle capacity over time.[53]





Option 1 meets every year's capacity requirement by deploying large solutions infrequently, whereas Option 2 meets annual needs through smaller and more continuous deployments. While the infrastructure deployed with Option 1 will continue to meet the required planning reserve margins decades into the future, it requires a significant upfront investment. Option 2 targets the near-term required planning reserve margins on a continuous basis. Both options ensure that the planning reserve margin for reliability purposes is met, but Option 1 results in higher idle capacity rates over the lifetime of the infrastructure in aggregate when compared to Option 2.

Extending the basic financial idea of the time value of money, paying for capacity today is more expensive than paying for capacity tomorrow – even before considering any cost decreases resulting from technological advancements. DER solutions that can preserve reliability, while delaying capital investments for new capacity until future periods, are inherently valuable to ratepayers. This value driver means that solutions that may look more expensive on a per unit of nameplate capacity basis are actually more cost effective on a net present value basis.

Value of Increased Flexibility in Modern Distribution Planning

The second source of value to be realized from modernizing planning stems from a related but separate challenge that grid planners face: the risk of suboptimal decisions arising from forecast error. This risk is primarily driven by two dynamics:

1. Long lead times are necessary to deploy traditional infrastructure.
2. Long depreciation lifetimes are allowed by regulators for those assets.

As a result, grid planners commonly make investment decisions many years into the uncertain future, and then charge customers for the maintenance, depreciation, profit and taxes associated with those assets over 20 to 30 years or more. Investment under uncertainty imposes risks, which, if not managed properly, create unforeseen ratepayer costs. Among other sources of uncertainty, grid planning and expansion using traditional bulky infrastructure is subject to demand growth uncertainty and technology uncertainty. Both of these forecast errors can be large and expensive.

Over-forecasting demand can result in an overbuilt system for which ratepayers must bear the full burden, even if the infrastructure was not needed. Under-forecasting demand can require the installation of suboptimal, expensive patchwork solutions, or threaten reliability if solutions cannot be provided in time. Similarly, on the technology side, inaccurately forecasting the future costs and capabilities of technologies may result in premature obsolescence as technological advancement dramatically reduces equipment costs or increases equipment efficiency. While private firms typically bear these investment risks in other industries, utility ratepayers bear 100% of these forecast error risks in the electric industry unless the utility regulator acts to disallow cost recovery.

Due to these risks, DERs with shorter lead times can offer real-option value (ROV) by delaying deployment until forecast uncertainty is smaller, effectively buying time for planners and reducing the probability of a mistake. While the value of real options can be significant, it is difficult to quantify without the requisite data, including historical loading data, historical forecasts, and current long-term project forecasts. These data needs are further elaborated on in the subsequent section.

Policy Considerations

The additional sources of value, including time value of money and real option value, associated with a transition towards integrated distribution planning that fully leverages DER deployments were explored above, but are not explicitly quantified due to the limited data publically available. Ongoing proceedings in California, such as the Distribution Resource Plan (DRPs) and Integrated Distributed Energy Resources (IDER), create important vehicles to share information between parties in order to explore these important but less conventional sources of value that are not yet well quantified.

V. Conclusion

In this report, we explored the capability of distributed energy resources to maximize ratepayer benefits while modernizing the grid. The opportunity associated with proactively leveraging DERs deployed over the next five years is significant, creating $1.4 billion a year by 2020 in net societal benefits across the state of California. Applying the state-wide methodology to a subset of real distribution capacity projects identified in California's most recent utility General Rate Case yielded similar results, suggesting DERs can cost effectively replace real-world planned distribution capacity projects today.

The impediments to capturing these benefits in practice remain significant. Utility incentives must be realigned to ensure that the full potential of DERs can be realized. Shifting the utility's core financial incentive from its current focus of "build more to profit more" towards a future state where the utility is financially indifferent between sourcing utility-owned and customer-driven solutions would neutralize bias in the utility decision making process. However, modernizing grid planning is also necessary. Grid planning must be updated to incorporate DERs into every aspect of grid planning, and the process itself must become radically more transparent with greater access to and standardization of data.

The benefits of achieving these changes would be real – and large. While initially complex to consider, the greater flexibility DERs can provide to grid planners and operators leads to greater reliability and resiliency. Similarly, the more targeted and incremental deployments of DERs can enable more efficient and affordable grids. Most importantly, utilities that can successfully modify planning processes would be able to fully take advantage of the assets their customers chose to adopt.

While no single report will adequately address all the issues – engineering, economic, regulatory – that naturally come with a transformative time in the industry, we hope that compiling these issues in one place, even with a high-level focus, advances the discussion and provides an overview of the critical topics for regulators and industry stakeholders to consider when evaluating the full potential of distributed energy resources.

About Grid Engineering Solutions

Our Grid Engineering Solutions team is leading efforts to make the 21st century's distributed grid a reality. At SolarCity, grid engineering is more than understanding how the current power system works and how to interconnect distributed energy resources. It encompasses a cross-functional approach to evaluating engineering, technology, economic, and policy considerations side-by-side. We apply our expertise in power systems engineering, energy economics, and advanced grid technology to unlock innovative solutions that enable the grid of the future.

The majority of the Grid Engineering Solutions team members, including the authors of this paper, are former utility engineers, economists, technologists, and policy analysts. We treat the design and operation of the electric grid as a major opportunity to partner across the energy industry, with the aim of driving innovation to benefit consumers and our environment. Collaboration across utilities, grid operators, regulators, national laboratories, philanthropists, environmentalists, distributed energy resource providers, energy service providers, and customers is paramount to meeting the challenge of modernizing our grid. We welcome any dialogue that helps foster the next generation of grid design and operations. For more information, please visit us at www.solarcity.com/gridx or contact us at gridx@solarcity.com.

Appendix 1: Overview of Traditional Avoided Cost Categories and Methodologies

The traditional avoided cost categories evaluated in this report are detailed in the following table. Descriptions of the avoided cost, overview of the CPUC Public Tool's treatment of these avoided costs, and TASC's adjusted methodologies are provided. The adjusted TASC methodologies are used to quantify the traditional avoided cost values used in this paper. See TASC NEM Successor Tariff filing for more details on quantification approach.[54]

AVOIDED COST	DESCRIPTION	CPUC PUBLIC TOOL METHODOLOGY	TASC INPUT
Energy + Losses	The value of wholesale energy that would otherwise be generated in the absence of DERs, adjusted for losses that would occur. In CA, the cost of carbon allowances from the Cap and Trade program is embedded in the wholesale energy value.	The Public Tool creates a forecast of future energy prices using a simplified dispatch model and applies those prices to the DER generation in each hour. The model also allows a locational multiplier to be applied to capture the additional value of DER generation that occurs in specific locations.	TASC used the default assumptions for calculating energy value, but utilized the locational multiplier with a value of 4.8%, which was the premium derived from the empirical correlation between DER locations and CAISO locational marginal prices (LMPs).
Generation Capacity	The value of avoiding the need for system generation capacity resources to meet peak load and planning reserve requirements.	The Public Tool calculates the long-run cost of capacity by determining the Cost of New Entry (CONE) for a combustion turbine, and nets that cost against the energy and ancillary services revenues that a plant would be expected to earn.	TASC used the default assumptions for net CONE, and assumed that the long-run marginal cost that net CONE represents is the value of capacity starting in 2017, also known as the Resource Balance Year (RBY).
Transmission Capacity	The value of avoiding the need to expand transmission capacity to meet peak loads.	The Public Tool allows the user to input a $/kW-year value for avoided transmission capacity. The model takes this input and assesses the avoided cost by taking into account the level of coincidence of DER generation with the coincident peak that drives transmission expansion.	TASC assumed the avoided cost was the marginal cost of transmission capacity, which was estimated to be $87/kW-year based on regression analysis of historical transmission costs and their correlation with load growth.
Distribution Capacity	The value of avoiding the need to expand distribution capacity to meet peak loads.	The avoided cost attributable to DERs takes into account the level of coincidence of DER generation with the drivers of these marginal costs, which are allocated to specific time periods by Peak Capacity Allocation Factors (PCAFs).	TASC assumed the avoided cost was the marginal cost of distribution capacity, which was sourced from each IOU's most recent CPUC general rate case.
Ancillary Services	The value of a reduced need for operational reserves based on load reduction through DERs.	The Public Tool defines the cost for ancillary services as a 1% of wholesale energy costs, and allocates the value based on hourly load.	TASC did not modify any assumptions with respect to how avoided ancillary services are calculated.
Renewable Energy Compliance	The value of reducing procurement requirements for renewable energy credits, due to reduced delivery of retail energy on which RPS compliance levels are based.	The Public Tool bases this value on the above market costs of RPS generation. Under a 33% RPS, each kWh of DER generation reduces the need for RPS generation by 0.33 kwh.	TASC assumed a 33% RPS by 2020 and did not modify any assumptions with respect to how avoided RPS costs are calculated.
Societal Benefits	The value of benefits that accrue to society, and are not costs directly avoided by the utility.	The Public Tool model provided the flexibility to insert assumptions for societal benefits based on $/tonne of emissions or $/kWh benefits.	TASC included the Environmental Protection Agency's value for the social cost of carbon, as well as estimates for NOx, PM10, land use, and water use benefits.

Appendix 2: Utility-Proposed Distribution Integration Investments in CA DRP

The following table presents the DER integration investment categories as identified in SCE's DRP filing. SCE's costs were scaled up to estimate total integration costs for all California utilities over 2016-2020. SCE cost estimates were stated at the category level, and were uniformly spread across the underlying investments. For each investment, applicability to DER integration is assessed using the threshold and screening questions identified in this paper. This quantification is necessarily high-level due to the lack of details provided, and additional details are necessary in order to fully evaluate investment plans.

INVESTMENT CATEGORY	INVESTMENTS	UTILITY COST CLAIM ($M)	APPLICABLE TO DERS (%)	RATIONALE
Distribution Automation	Automated switches w/enhanced telemetry	$355	0%	Business as usual: Automation programs are reliability driven and not necessary for DER integration.
	Remote fault indicators	$355	0%	Business as usual: fault indicators are reliability driven and not necessary for DER integration.
Substation Automation	Substation automation	$346	0%	Business as usual: Automation programs are reliability driven and not necessary for DER integration.
	Modern protection relays	$346	60%	Investment in protective relay upgrades can be valid at high penetration of DERs, although setting changes can frequently eliminate need for relay replacements.
Communication Systems	Field area network	$444	0%	Business as usual: supports preexisting utility efforts to extend SCADA visibility throughout distribution system.
	Fiber optic network	$444	0%	
Technology Platforms and Applications	Grid analytics platform	$119	33%	Investments in identification and communication of grid needs are valid for high DER penetrations. However, only some of these costs are applicable to DERs as these tools broadly support grid modernization and will be used to process data from smart meters and utilityi grid devices.
	Grid analytics applications	$119	33%	
	Long-term planning tool set	$119	50%	Long-term planning and distribution circuilt modeling tools are used to forecast all grid needs and scenarios, including reliability, loads, and DERs; therefore, only a portion of these costs are driven by DER integration.
	Distribution circuit modeling tool	$119	50%	
	Interconnection application processing	$119	100%	Investments that support DER interconnection are directly related to DER integration.
	DRP data sharing portal	$119	100%	
	Grid and DER management system	$119	50%	Grid and DER management systems are used to manage all grid assets, including utility equipment and DERs; only a portion of these costs are driven by DER integration.
	System architecture and cyber security	$119	25%	As the grid becomes more reliant on more granular visibility and control, system architecture and cybersecurity investments are needed irrespective of DERs. Therefore, only a portion of these costs are driven by DER integration.
	Distribution Volt/VAR optimization	$119	25%	Business as usual: Volt/VAR Optimization programs preexisted DER deployments; while DERs increase Volt/VAR benefits, only a portion of these costs are driven by DERs.
Grid Reinforcement	Conductor upgrades to a larger size	$1,168	50%	Capacity and conductor upgrades driven primarily by safety, reliability and resiliency needs. However, capacity investments for high DER penetrations resulting in thermal limit violations are valid.
	Conversion of circuits to higher voltage	$1,168	10%	Business as usual: Supports preexisting utility efforts to convert circuits to higher voltage. Incremental costs associated with accelerated replacement could be driven by DER integration in some cases.
Total		**$5,697**	**25% ($1,450)**	

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[43] Pacific Gas and Electric only provides project-level information for distribution capacity projects exceeding $3 million. Investment in smaller distribution capacity projects is incorporated into the broader distribution budget, but is not broken out in any detail.
[44] This calculation reflects a 25-year useful life of assets and ratebase depreciation schedule with an authorized WACC of 7.8% and corporate tax rate of 42%. Property taxes are omitted. Project expenses are based on the O&M share of PG&E's 2014 distribution revenue requirement (41%), but revised down to a 30% ratio acknowledging that a portion of O&M is fixed O&M as opposed to variable O&M. CPUC Public Tool's default value for the societal discount rate of 5% is used to calculate societal net present cost.
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Data Requirements for Grid Needs / Planned Investments

Category	Data Type	Data Request	Intended Use	Temporal and Spatial Granularity	Data Format and Transfer Method
Project Identification	Project name	Individual identifying name or serial number for each planned investment project.	Ensure each individual project planned by utility is accounted for and readily identifiable for third-party consideration of alternative investments.	Issued as part of the annual distribution planning process. One entry per planned investment project.	Issued as part of a machine-readable downloadable data file of planned grid investments.
	Location/ geography	GPS coordinates, city, zip code, and electrical configuration (node location by: substation, feeder, node, line section, downstream Line Recloser (SCADA switch).	Allow for geographical mapping of each project	Issued as part of the annual distribution planning process. Location identified down to the node.	Issued as part of a machine-readable downloadable data file of planned grid investments.
Project Requirements	Deployment timelines	Planned start of project deployment (e.g. start of installment of equipment), planned start of project operation, and required start of project to meet identified grid need.	Assess whether DERs can be deployed to offset investments	Issued as part of the annual distribution planning process. One entry per planned investment project.	Issued as part of a machine-readable downloadable data file of planned grid investments.
	Planned asset life	Expected operating life of planned investment.	Assess whether DERs can be deployed to offset investments	Issued as part of the annual distribution planning process. One entry per planned investment project.	Issued as part of a machine-readable downloadable data file of planned grid investments.
	Primary need served	Grid need or needs that have been identified as the underlying requirement for the planned project: capacity, power quality (VARs, voltage regulation), frequency regulation, reliability, resiliency, other (specified).	Assess whether DERs can be deployed to offset investments	Issued as part of the annual distribution planning process. One entry per planned investment project.	Issued as part of a machine-readable downloadable data file of planned grid investments.
	Secondary need served	Grid need or needs that are not required or motivating the planned project, but which are valuable secondary impacts or benefits the planned project could provide: capacity, power quality (VARs, voltage regulation), frequency regulation, reliability, resiliency, other (specified).	Assess whether DERs can be deployed to offset investments	Issued as part of the annual distribution planning process. One entry per planned investment project.	Issued as part of a machine-readable downloadable data file of planned grid investments.
Performance Requirements	Performance requirements	Planned required operation of the project including: operation window (e.g. 24/7, HE 7 - HE 20, summer afternoon hours, etc.), operation duration (e.g. 24 hours, 2 hours, 5 minutes, etc.), required response time following trigger (e.g. 24 hours, 2 hours, 4 seconds, etc.).	Assess whether DERs can be deployed to offset investments	Issued as part of the annual distribution planning process. One entry per planned investment project.	Issued as part of a machine-readable downloadable data file of planned grid investments.

Data Requirements for Hosting Capacity

Category	Data Type	Data Request	Intended Use	Temporal and Spatial Granularity	Data Format and Transfer Method
Circuit Model	Circuit Models	GIS or distribution analysis software model; line equipment; length of lines; latitude and longitude coordinates.	Model individual circuits.	Updated models made available as projects are implemented; existing models made available ongoing. Models at the feeder level.	Made available in whatever format preserves the most information. Could be downloadable from online maps or through a data portal.
Loading	Feeder-Level Loading	MW load; VARs; Amps; Volts.	Perform steady state integrated hosting capacity analysis.	Updated data made available monthly; historical data made available ongoing; 15 minute granularty; node location by: substation, feeder.	Made available in a machine-readable downloadable data file. Could also be available through online maps.
	Customer Type Breakdown	Number of customers by rate type; customer type: i.e. residential, commercial, industrial; agricultural; household income levels; number of demand response (DR) customers; DR device types; DR event participation statistics.	Estimate load curve based on typical customer loading	Updated data made available monthly; historical data made available ongoing; node location by: substation, feeder, node, line section, downstream Line Recloser (SCADA switch)	Made available in a machine-readable downloadable data file. Could also be available through online maps.
	Circuit Node Loading	MW load; VARs; Amps; Volts.	Allocate loading along circuit.	Updated data made available monthly; historical data made available ongoing; node location by: substation, feeder, node, line section, downstream Line Recloser (SCADA switch).	Made available in a machine-readable downloadable data file. Could also be available through online maps.
	Existing DER Capacity	DER capacity MW	Incorporate existing DER capacity into hosting analysis	Updated data made available monthly; historical data made available ongoing; node location by: substation, feeder, node, line section, downstream Line Recloser (SCADA switch).	Made available in a machine-readable downloadable data file. Could also be available through online maps.
Equipment Details	Equipment Thermal Ratings	Thermal equipment ratings for conductor and line equipment by location (switches, breakers, transformers, voltage regulating equipmet, voltage protection equipment, etc.).	Evaluate thermal loading limits.	Updated lists made available as changes are implemented.	Made available in a machine-readable downloaded data file and included in circuit models.
	Voltage Regulating Equipment	Ratings of voltage regulating equipment by location; Voltage equipment settings (unique or typical settings) including bidirectinoal capability.	Evaluate voltage equipment performance.	Updated lists made available as changes are implemented; existing equipment lists and settings made available ongoing.	Made available in a machine-readable downloaded data file and included in circuit models.
	Protection Equipment	Ratings of protection equipment by location; Protection equipment settings (unique or typical settings).	Evaluate protection criteria.	Updated lists made available as changes are implemented; existing equipment lists and settings made available ongoing.	Made available in a machine-readable downloaded data file and included in circuit models.

Locational Value Data

Category	Data Type	Data Request	Intended Use	Temporal and Spatial Granularity	Data Format and Transfer Method
Capacity	Planned capacity projects	Project details planned within 10 years; MW capacity.	Assess where DERs can be deployed to offset investment.	Issued as part of the annual distribution planning process. Location identified down to the node.	Made available in a machine-readable downloadable data file. May also require circuit models.
	DER and load growth forecasts vs. integrated capacity.	DER growth forecast MW; load growth forecast MW; integrated DER MW capacity.	Assess when DER and load growth will surpass integrated capacity; compare timing against planned projects.	Updated data made available monthly; historical data made available ongoing, location identified down to the node.	Made available in a machine-readable downloadable data file. Could also be available through online maps.
Voltage / Power Quality	Planned voltage / power quality projects	Project details planned within 10 years; voltage and power quality results expected.	Assess where DERs can be deployed to offset investments.	Issued as part of the annual distribution planning process. Location identified down to the node.	Made available in a machine-readable downloadable data file. May also require circuit models.
	Observed violations statistics	SCADA voltage violation data: i.e. overvoltage, undervoltage, voltage flicker, voltage imbalance, etc.; viloation time stamp; violation remedy.	Assess whether investment plan matches needs, and identify areas to target DERs.	Updated data made available monthly; historical data made available ongoing, location identified down to the node.	Made available in a machine-readable downloadable data file. Could also be available through online maps.
	Customer complaints	Complaint type; complaint time stamp; violation verification; violation type; remedy.	Assess whether investment plan matches needs, and identify areas to target DERs.	Updated data made available monthly; historical data made available ongoing, location identified down to the node.	Made available in a machine-readable downloadable data file. Could also be available through online maps.
Reliability / Resiliency / Security	Planned reliability / resiliency / security projects	Project details	Assess where DERs can be deployed to offset investments.	Issued as part of the annual distribution planning process. Location identified down to the node.	Made available in a machine-readable downloadable data file. May also require circuit models.
	Reliability statistics <u>excluding</u> and <u>including</u> major events	Reliability statistics: CAIDI, SAIDI, SAIFI, CESO, DEMI; worst performing circuits; major event days; automated restoration operation.	Assess whether investment plan matches needs, and identify areas to target DERs.	Updated ata made available monthly; historical data made available ongoing. Location identified down to the node.	Made available in a machine-readable downloadable data file. Could also be available through online maps.
	Existing supply redundancy level	Redundancy MW capacity; # of supply feeds (use as proxy for resiliency)	Assess whether investment plan matches needs, and identify areas to target DERs.	Updated data made available monthly; historical data made available ongoing. Location identified down to the node.	Made available in a machine-readable downloadable data file. Could also be available through online maps.
	Probability of major event	Probability of major event by geographic area	Assess whether investment plan matches needs, and identify areas to target DERs.	Updated data made available monthly; historical data made available ongoing. Location identified down to the node.	Made available in a machine-readable downloadable data file. Could also be available through online maps.

EFCA Exhibit #4 - 18 Pages

BROOKLYN QUEENS DEMAND MANAGEMENT DEMAND RESPONSE PROGRAM GUIDELINES

June 28, 2016

conEdison

EVERYTHING MATTERS

BQDM DR Program Overview

1. Purpose

The intent of this document is to provide an overview of the Brooklyn Queens Demand Management Demand Response Program (BQDM DR Program) and help aggregators and direct customers participate in the program. This document is **not** intended to provide a listing of all BQDM DR Program rules and requirements but is rather an overview of the BQDM DR Program including key details that are expected to be pertinent and important to participants and stakeholders. Please refer to the BQDM DR Program Agreement Package for comprehensive program rules.

2. Overview of Demand Response ("DR")

At Con Edison we constantly plan for and maintain our infrastructure so we are able to provide electricity reliably to our customers, including during periods of high demand that occur during summer months when temperatures peak and ACs across NYC are at full blast. During such periods, demand for electricity spikes, and though our electric grid is designed to handle high levels of energy use, extended periods of peak demand can put stress on the grid. To help relieve such stress during peak periods, Con Edison calls on commercial, industrial, and residential customers enrolled in our Demand Response (DR) Programs to cut back on their energy use for a few hours. Collectively, this limited energy use reduction significantly strengthens grid reliability.

In exchange for participating as a DR resource providing energy reduction during peak hours in the summer, enrolled customers (directly or through aggregators) earn compensation based on the amount of energy (measured in kilowatts) they are willing to cut back on, for a few hours when called on by Con Edison. The figure below illustrates results of actions taken by a customer in reducing energy use when a 4 hour DR event is called.

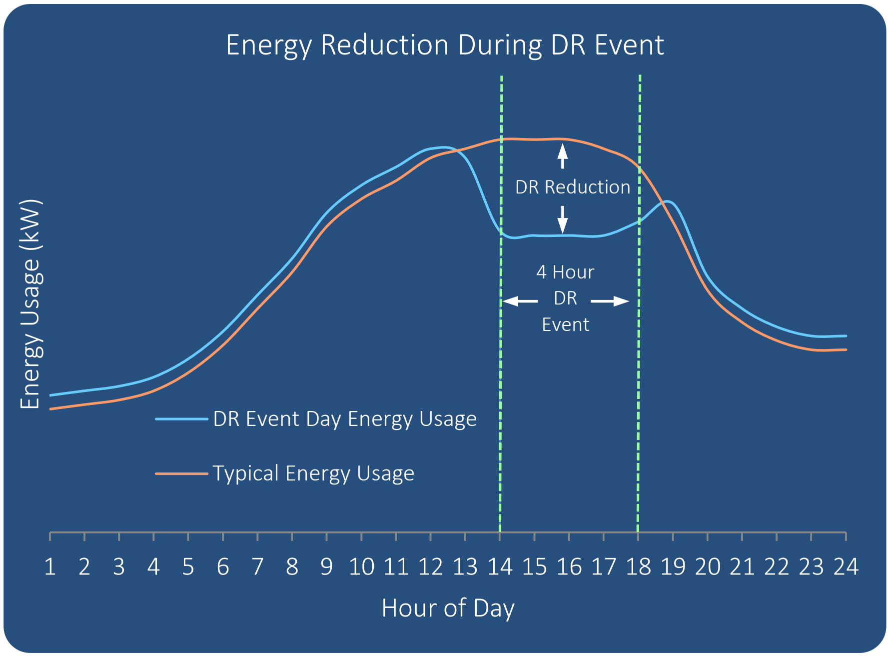

Figure 1

Over 1,000 customers across many sectors have enrolled in Con Edison's existing Demand Response programs. From commercial office buildings to hospitals, from waste water treatment plants to schools, from nursing homes to university campuses, all types of customers who meet our requirements can participate in Demand Response programs. Customers provide DR resources through various strategies:

- Turning off non-essential lighting
- Adjusting air conditioning set points and pre-cooling facilities
- Reducing elevator usage
- Reducing building air flow
- Discharging batteries
- Adjusting manufacturing schedules
- Using thermal storage capabilities
- Turning on backup generators
- Switching over to steam chillers
- Using building management systems for managing energy use
- And many more….

3. Brooklyn Queens Demand Management Demand Response Program

The BQDM Program was approved by the New York Public Service Commission on December 12, 2014, when it issued its Order Establishing Brooklyn/Queens Demand Management Program. Under the BQDM program, Con Edison intends to procure 52 MW of non-traditional resources by summer of 2018, with 41 MW of the total 52 MW expected to be provided by customer-side solutions such as DR, energy efficiency, storage, fuel cells and CHP. These resources will enable the deferral of a major new substation build by over 5 years while resulting in benefits to customers.

Con Edison is acquiring DR resources as they will play a key role in meeting BQDM program needs by providing load relief during critical hours on peak summer days. Figure 2 provides an illustration of how DR provides such critical load relief and how it is an important portion of the BQDM program portfolio of solutions; a portfolio that collectively enables deferral of the substation even while maintaining system reliability. In particular, Con Edison is seeking to use DR resources to provide load relief between 4 pm and midnight in two separate 4-hour blocks for summers of 2017 and 2018.

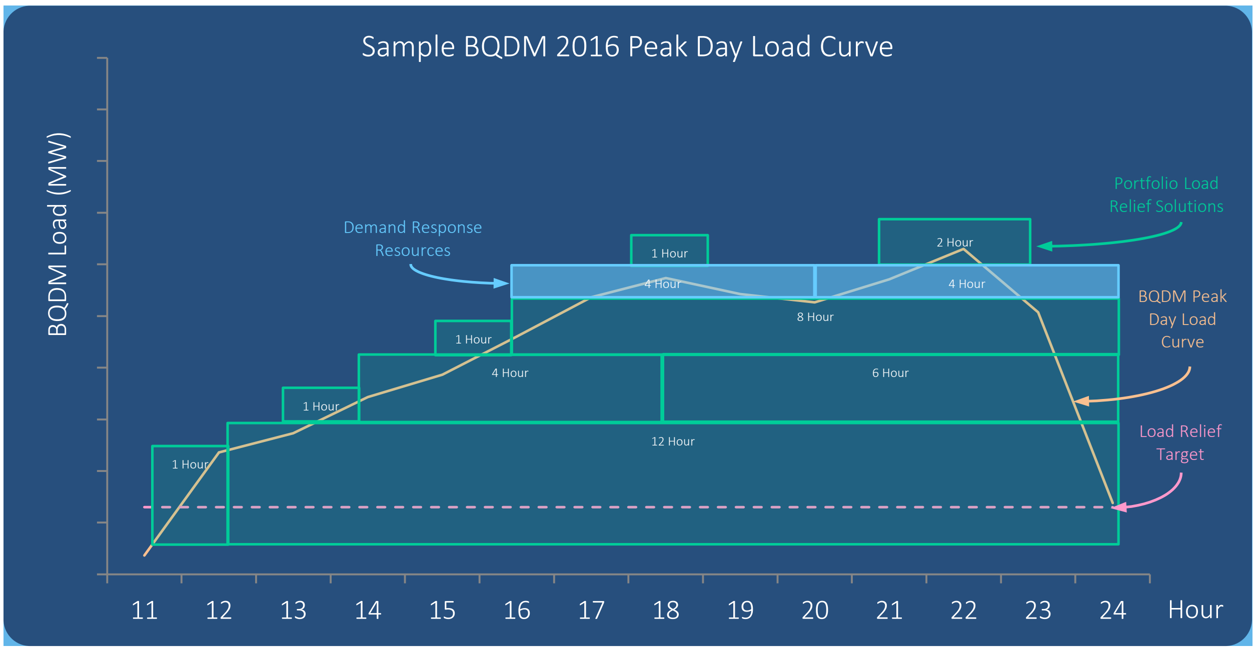

Figure 2

Con Edison currently offers two DR programs – Commercial System Relief Program or CSRP to reduce network peaks and Distribution Load Relief Program or DLRP for operational contingencies – that provide needed load relief to the distribution system. Con Edison compensates participants in these programs through a reservation payment for being available and a performance payment based on actual amount of load relief provided when called upon.

With the BQDM DR Program, Con Edison provides an opportunity to DR resources to participate and earn significant compensation by supplying load relief in the areas targeted by BQDM program, instead of through the CSRP program; Con Edison does not plan to offer CSRP in the BQDM areas (the electrical networks of Crown Heights, Ridgewood and Richmond Hill) in 2017 and 2018, subject to regulatory approval. See following section for a description of the BQDM area.

Con Edison is using a competitive descending clock auction mechanism to procure DR resources in the BQDM area. The auction ceiling price, i.e., **the maximum price at which bidding will be allowed and at which bidding can be expected to commence, will be set at a level significantly higher than existing CSRP**

reservation payment levels, providing an opportunity for significantly greater reservation compensation if the auction clears at a relatively high price. Additionally, compensation for performance when called upon, will also be set at higher levels as compared to the CSRP program. While the BQDM DR Program expects to generally provide higher compensation to DR resources compared to the CSRP, it will also include both bonus and penalty schemes to incent consistently high performance, and thus reliability, and discourage unavailability and/or overestimation of load relief.

While the BQDM DR Program will seek DR resources for 2017 and 2018, Con Edison anticipates that it will continue to offer DR programs beyond the 2018 timeframe. Con Edison expects that DR resources that participate in the BQDM DR Program for 2017 and 2018 will be able to continue to provide network load relief through CSRP and/or other programs in existence at the time.

What is the BQDM Program Area?

The BQDM DR Program Area is made up of the following electrical networks:

- Crown Heights
- Richmond Hill
- Ridgewood

The BQDM DR Program Area includes north central and eastern Brooklyn neighborhoods, including parts of Greenpoint, East Williamsburg, Bushwick, Bedford-Stuyvesant, Crown Heights, East Flatbush, Brownsville, and East New York, and southwestern Queens neighborhoods, including parts of Richmond Hill, Howard Beach, Broad Channel, Ozone Park, South Ozone Park, Woodhaven and Kew Gardens.

The map in Figure 3 illustrates the boundaries of the three applicable networks. Con Edison notes that the boundaries provided here are approximations of the physical boundaries of the electrical networks. Aggregators with customers as well as direct market participants intending to participate in the BQDM DR program should confirm with Con Edison that their chosen customer locations are within the networks targeted by the BQDM program.

Figure 3

4. BQDM DR Requirements and Eligibility

A. What are the requirements to be a BQDM DR Aggregator?

In order to participate in the BQDM DR Program there are three (3) categories of requirements:

- **Systems** – DR providers must have systems in place (namely phone, email, and Microsoft Excel) to receive event notifications, notify customers, and submit enrollments electronically.
- **Portfolio** – DR providers must enroll at a minimum 50 kW across their portfolio in order to participate in each product.
- **Financial** – DR providers will have to meet certain financial requirements (these are in place to protect Con Edison) since the program will have financial penalties as a mechanism to achieve the desired MW reductions upon which the communities will rely.

For more information on the specifics of the DR provider requirements please see the BQDM DR Program Agreement package.

B. What are the requirements for customers to participate in BQDM DR?

To be eligible to participate in the BQDM DR Program, customers must:

- Be located in the BQDM DR area (outlined above)
- Have a Con Edison communicating interval meter. See the links below for costs associated with installing a Con Edison communicating interval meter and an installation manual that helps you navigate the meter upgrade process.
  - Interval Meter Information
  - Interval Meter Upgrade Manual
- Receive Con Edison electric service
- Customers are not allowed to increase their load from their baseline between the hours of 11 AM and 12 AM on event days
  - Participants cannot use a strategy that increases usage outside of the auction product window. If load increases 15% or less from the baseline, there are no penalties; however baseline load increases above 15% outside of the auction product window within the 11 am - 12 pm timeframe will be added back such that it affects the Performance Penalty. Penalty payments due to under performance are determined by the Annual Performance Factor for performance factors below 85%. Lower performance incurs a graduated increasing penalty. In other words, if a participant increases electric load 15% or more above its baseline, the kWh above the 15% threshold from the hours of 11 AM to 12 AM will be netted against the participant's cumulative kWh reduction during the event window.

Customers who receive power from an ESCO or NYPA are also eligible to participate in all Con Edison DR programs.

C. Technology Requirements and Eligibility

Curtailment Technologies

There are no restrictions on the strategies and technologies that customers can utilize to curtail their electric load during DR events. We encourage you to develop strategies that yield a "controlled reduction" – electric reduction that is reliable and that is not overly burdensome.

Generation (not exporting onto the grid)

There are emissions requirements for customer-sided fossil fuel generation equipment. New York State Department of Environmental Conservation ("DEC") air permits must be submitted along with meeting other BQDM DR requirements. In addition, it is the customer's responsibility to comply with all city, state, and federal requirements. For the detailed requirements regarding fossil fuel fired generation participation in DR please see the BQDM DR Program Agreement.

For non-fossil fuel powered equipment, it is the customer's responsibility to meet all city, state, and federal requirements but Con Edison does not require any permitting documentation for enrollment in BQDM DR.

Generation (exporting onto the grid)

Con Edison will permit resources that export excess power on to the grid, i.e., customers categorized as belonging to Service Classification No. 11 per Con Edison tariff (Refer to Leaf 461 or page 83 of http://coned.com/documents/elecPSC10/SCs.pdf), to participate in the BQDM DR Program. If such a resource operates in a manner such that there may be a baseline that better estimates load relief as compared to a standardized baseline, we are open to accepting, at our discretion, an appropriate, alternate baseline. If you would like to discuss such an alternate, please contact us via e-mail at bqdmauction@coned.com with information specific to your proposed DR resource.

Energy Storage

Con Edison does not require any permits for energy storage system participation in the BQDM DR Program. Con Edison expects that customers comply with all city, state, and federal regulations and permitting requirements.

5. General BQDM DR Program Rules

A. What is the BQDM DR dispatch criteria?

Con Edison intends to call a BQDM DR event when it expects that the next day will be a peak day in the BQDM Program Area (electrical networks of Crown Heights, Ridgewood and Richmond Hill). Con Edison's dispatch protocols currently being developed for the BQDM DR Program define a peak day as follows:

- For DR resources providing load relief between 4 pm - 8 pm - When the anticipated peak electrical load in the BQDM area the following day is no less than 97% of the summer peak forecast, and
- For DR resources providing load relief between 8 pm – 12 am - When the anticipated peak electrical load in the BQDM Area the following day is no less than 93% of the summer peak forecast.

Con Edison expects that there will be an average of 3-6 calls each year for each product.

B. How much notification will BQDM DR give before events?

Con Edison will notify aggregators and direct participants of the BQDM DR program 21 hours in advance of an event. If an event is called, DR resources in on or both call windows will be notified of the event (more details below on call windows). Participants will be notified of events via telephone and email.

C. When will participants need to provide load relief?

For the BQDM DR Program there will be two (2) call windows of four (4) hours each:

- 4 PM to 8 PM
- 8 PM to 12 AM

Participants will be able to provide DR capability in one or both of the call windows (more details on this and the DR auction later in the document). Participants are not allowed to increase their load from their baseline between the hours of 11 AM and 12 AM on event days.

D. How many events does Con Edison expect to call for BQDM DR?

The BQDM DR capability period runs from May 1st through September 30th for 2017 and 2018. Con Edison expects that 4 events will be called during the capability period and not more than 15 events are expected to be called during the capability period (May 1st through September 30th).

E. How will the BQDM DR Program fit with Con Edison's Other DR Programs?

The BQDM DR Program is expected to replace the Commercial System Relief Program (CSRP) for the BQDM networks (Crown Heights, Richmond Hill, and Ridgewood) pending approval from the New York State Public Service Commission (see Case 16-E-0236). The Distribution Load Relief Program (DLRP, also known as the 2 hour notification program) will still be offered in the BQDM area. Customers are eligible to participate in the BQDM DR program, DLRP, and the NYISO's DR programs concurrently but will be obligated to perform during Con Edison's DR events (BQDM DR and DLRP).

If both Con Edison DR programs call events on the same day, customers enrolled in the applicable DR programs will be expected to respond to all event hours regardless of coincidence (i.e. regardless of whether the event windows overlap or not).

Participants enrolled across both Con Edison DR programs are expected to meet the requirements and rules of each applicable Demand Response program.

F. How does Con Edison measure DR performance?

During a DR event, participants reduce electrical consumption for a period of 4 hours. In order to analyze participants' DR performance and if they met their reduction pledge, Con Edison produces a "baseline" curve which represents participants' projected electrical usage if an event had not been called. It is relative to the participants' baseline curve that Con Edison measures DR performance.

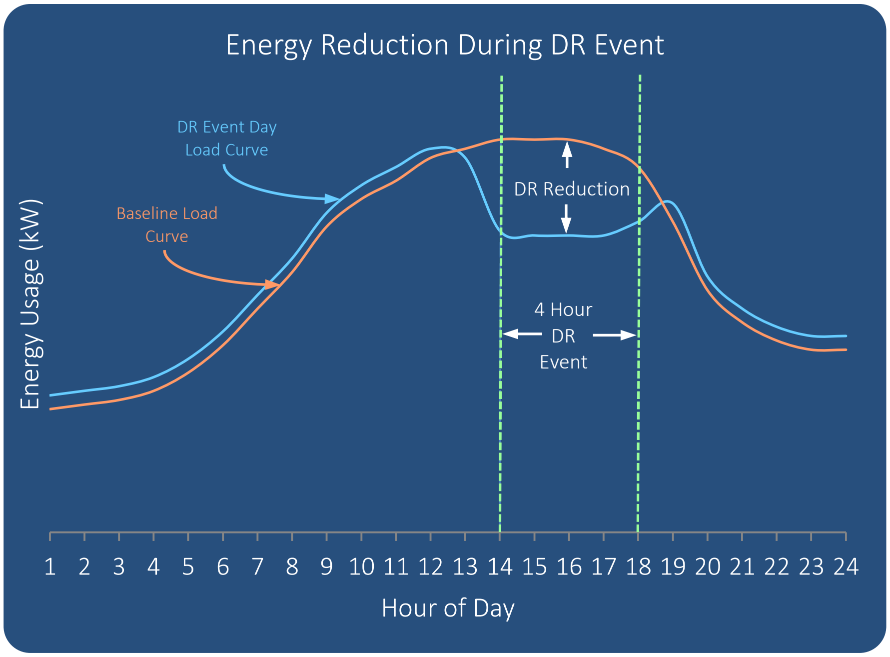

Figure 4

Con Edison follows its [Customer Baseline Load Procedure] to develop the baseline load curve. In practice the customer baseline procedure looks back at a DR participant's last 30 days of 15 minute interval electrical usage data prior to an event and averages the usage from the five (5) days with the highest usage during the event window. This is known as the Average Day Baseline.

Con Edison offers another baseline methodology that participants can select upon enrollment which is called the Weather Adjusted Baseline. This baseline methodology applies a scaling factor to the Average Day Baseline based on actual load on the day of the event. The intent behind the Weather Adjusted Baseline is to account for how a participant's typical load might change depending on the weather of the event day. For example, say the majority of a participant's electric load is correlated with temperature; if the average temperature across the five days selected for the Average Day Baseline is 80 degrees Fahrenheit and the temperature on the DR event day is 98 degrees Fahrenheit then the Average Day Baseline might not accurately capture the participant's baseline. The Weather Adjusted Baseline methodology addresses the issue described above.

In addition, participants can propose their own baseline methodology. Con Edison will analyze the proposed baseline methodology in terms of accuracy and bias and reserves the right to accept or reject any proposed baseline methodologies.

Please refer to the [Customer Baseline Load Procedure] for the in depth mechanics of the methodology.

G. BQDM DR Enrollment

The enrollment process for the BQDM DR Program breaks down into 4 steps as illustrated below. This section will give a high level introduction to the enrollment process. For the comprehensive BQDM DR enrollment mechanics please see the BQDM DR Program Agreement package.

Figure 5

1. BQDM DR Auction

The BQDM DR program will set the DR incentive price and allocate resources through a descending clock auction (for an introduction to the auction mechanics see the BQDM DR Auction Overview section below). Shortly after the completion of each auction, Con Edison will announce the winners, the kW amount each winner cleared, and a single clearing price for all resources for a product in the auction. Con Edison does not expect that each DR provider that clears the auction will already have a complete portfolio of accounts that make up the kW cleared in the auction, but rather the kW amount cleared for each DR provider represents the cumulative kW across its portfolio that Con Edison expects each DR provider to enroll before the capability period.

2. Mutually Exclusive Bids:

A bidder may choose to bid the same 4-hour load reduction quantity (e.g., 1 MW) in both of the 2017 auctions (4 PM to 8 PM and 8 PM to 12 AM) and/or both of the 2018 auctions. To do so, enter the same quantity in a single row in the table below and mark the row “Mutually Exclusive”. In this case, should the bidder be awarded, Con Edison will use its best efforts to award the mutually exclusive bid which has the higher clearing price.

3. All or Nothing Bids

A bidder who can deliver load relief for 8 hours and wishes to clear auctions for both products (4 pm to 8 pm and 8 pm to 12 am) for a given year (2017 or 2018) may choose the “All or Nothing” option. To do so, enter the same quantity in a single row in the table below and mark the row “All or Nothing”. In this case, should the bidder be awarded, Con Edison will award the bidder for both the 4 pm to 8 pm and 8 pm to 12 am products.

4. DR Resource Deficiency Declaration

After the DR auctions, DR providers will have roughly 6 months before they have to declare any deficient DR resources. At a high level, the DR Resource Deficiency Declaration represents a mechanism for DR providers to reduce the size of their portfolios, on which Con Edison will calculate performance (see below for more information about DR performance calculations), for the DR capability period. A DR provider might declare deficient DR resources if they are unable to enroll customers to meet their load relief pledge and believe the associated financial penalty is less than the penalty associated with poor performance of a final DR portfolio during the capability period.

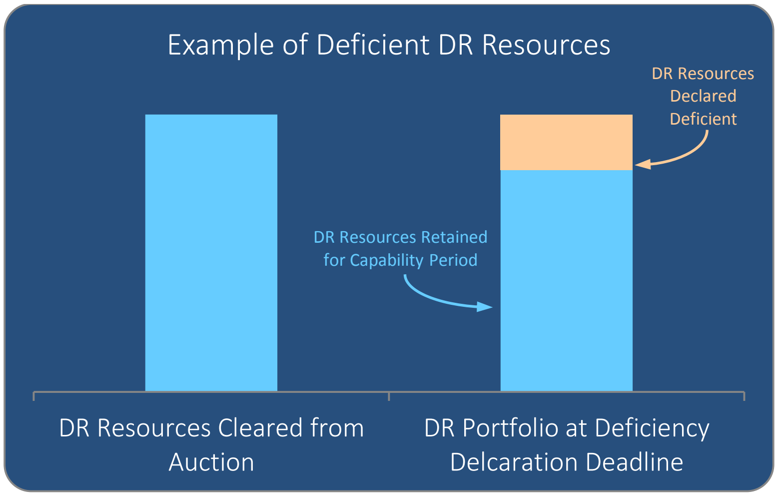

Figure 6

5. DR Resource Addition

Depending on the quantity of DR resources declared deficient by different DR providers, Con Edison may allow DR providers who have **not** declared any deficient resources to increase their portfolio size. For more detailed please see the BQDM DR Program Agreement package.

6. Final DR Portfolio Enrollment

The final portfolio enrollment deadline is the date by which DR providers must submit the customer account numbers, individual customer DR pledge amounts, generator permits, and any other information required to complete the enrollment process. For DR providers that currently participate in CSPR or DLRP, this deadline is similar to the enrollment deadline for those programs.

H. BQDM DR Auction Overview

The BQDM Demand Response reservation payment rate (see the Payment section below for more information on how payments will be structured) will be determined through a descending clock auction. Through the BQDM DR program, Con Edison is procuring DR Resources through a dynamic market auction to efficiently set the incentive price.

The section below gives a high level introductory description of the how the BQDM auction will work. Exhaustive auction training material will be distributed leading up to the auction date in addition to live training sessions.

Why an auction?

Con Edison believes a descending clock auction will facilitate a market acquisition process that is cost-effective and provides opportunities for demand response resources to meet Con Edison's performance objectives while earning competitive compensation.

How will it work?

The BQDM DR auctions will be hosted through a real-time online auction platform. Interested Demand Response Providers must submit a prequalification application to be granted approval by Con Edison to participate in the auctions. Once approved, participants will be given formal auction training which will train participants on how to use the platform to participate in the auction.

Con Edison intends to conduct four (4) different auctions, one (1) for each product:

July 27, 2016
Auction for 2017 products: Two call windows of four hours each

- **Product 1:** 8 PM to 12 AM *(auction hosted at 10 AM – 12 PM)*
- **Product 2:** 4 PM to 8 PM *(auction hosted at 1 PM – 3PM)*

July 28, 2016
Auction for 2018 products: Two call windows of four hours each

- **Product 3:** 8 PM to 12 AM *(auction hosted at 10 AM – 12 PM)*
- **Product 4:** 4 PM to 8 PM *(auction hosted at 1 PM – 3PM)*

Bidders will not be permitted to change their load reduction quantities beginning 24 hours prior to the start of the auction. For each auction, a bidder may elect to bid more than one quantity of load reduction. Multiple bids must be structured in a way that, should all bids be selected the supplier is capable of delivering the total quantity offered. The only exception to the foregoing is mutually exclusive bids, as described immediately below.

- **MUTUALLY EXCLUSIVE BIDS**:

A bidder may choose to bid the same 4-hour load reduction quantity (e.g., 1 MW) in both of the 2017 auctions (4 PM to 8 PM and 8 PM to 12 AM) and/or both of the 2018 auctions. To do so, enter the same quantity in a single row in the table below and mark the row "Mutually Exclusive". In this case, should the bidder be awarded, Con Edison will use its best efforts to award the mutually exclusive bid which has the higher clearing price.

- **ALL or NOTHING BIDS**:

A bidder who can deliver load relief for 8 hours and wishes to clear auctions for both products (4 pm to 8 pm and 8 pm to 12 am) for a given year (2017 or 2018) may choose the "All or Nothing" option. To do so, enter the same quantity in a single row in the table below and mark the row "All or Nothing". In this case, should the bidder be awarded, Con Edison will award the bidder for both the 4 pm to 8 pm and 8 pm to 12 am products.

Bid Blocks

Auction participants will bid DR resources into each auction in "blocks". The minimum and maximum block size is 50 kW and 2,000 kW respectively and each participant can have up to 5 blocks per auction for a total of 10,000 kW of DR resources that each participant can bid into each auction (one auction per product). The number and size of each block that a participant submits into an auction is set prior to the start of the auction and cannot be changed once the auction opens. Each DR resource block will be considered independently and therefore participants can bid different prices ($/kW/year) for each block. The intent of the blocks is to give DR providers the flexibility to bid different prices for different DR resources in their portfolio, perhaps depending on technology or for existing versus new customers.

Auction Bidding

Each of the four descending clock auctions will begin at a price no higher than the pre-announced ceiling price. During the live auction participants will bid a price for each of their blocks. Once a bid has been placed, the system will associate a rank with each block-bid combination where a rank of 1 represents the low bid of any block from all auction participants. Participants will compete to improve the rank of each of their blocks, which will be updated in real time, by bidding lower prices. Participants do not necessarily have to bid lower than the lowest price, but rather can bid prices lower than their current bid price to improve the rank of each of their blocks.

During the auction, each participant will see:

- The lowest bid in $ / kW / year (corresponding to rank 1)
- The bids associated with each of their blocks
- The ranks associated with each of their blocks
- The time remaining in the auction
- Any real-time communications from Con Edison during the auction through “chat messaging”

During the auction, each participant will **not** be able to see:

- The ranks of blocks associated with other auction participants
- The size (kW) of blocks associated with any other auction participants

Auction Timing

The auction will start with a 15 minute clock that is counting down. Any bids placed in the last 2 minutes of the clock will add an additional 2 minutes to the clock. The auction will end when the clock runs out, or when the total time of the auction is 2 hours, whichever occurs first.

How is the auction cleared?

After the auction is complete Con Edison intends to clear the auction at the price where the quantity of kW DR meets the product’s needs. All providers selected will receive the clearing price even if multiple bidders bid prices less than the clearing price. Please see the image below for an illustration of this concept.

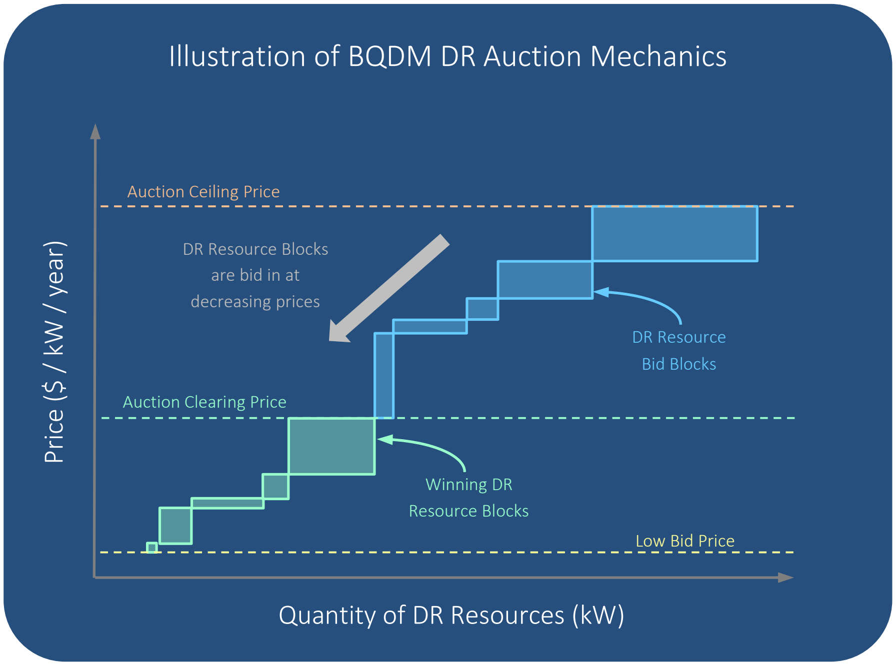

Figure 7

What happens after auction clears?

Once Con Edison has cleared the auction, it is intended that award notifications will be sent over to the winning bidders by end of day.

Each auction is awarded separately from the other auctions. All suppliers who are awarded in each auction will be awarded the clearing price.

I. Payments and Penalties

Under the BQDM DR program a single net payment (comprising all compensation net penalties) will be made or will be due after end of capability period, i.e., after September 30th of the applicable year, but before November 20th of the same year.

1. Early Exit Penalty Payment:

If a DR Provider will not be able to deliver the amount that it cleared in the auction for any of the DR Product, it can be relieved of that obligation by declaring the deficiency and paying the Early Exit Fee.

Early Exit Fee = (Deficient Quantity kW) × (Auction Clearing Price) × (10%)

The Portfolio Quantity is the Cleared Quantity less the Deficient Quantity. Performance Factor, Performance Penalties, Reservation Payments, Bonus Payments, etc. will be made on the Portfolio Quantity.

For each product year, the deficiency must be declared by February 15 and paid to Con Edison by February 21.

Example:

- DR Product: 4pm – 8pm, 2017
- Auction Clearing Price: $100/kW/year
- Cleared Quantity for DR Provider: 500 kW
- Deficiency declaration on 2/15/2017: 50 kW
- Early Exit Fee paid by 2/21/2017:
  50 kW × ($100/kW/Capability Period) × 10% = $500
- Portfolio Quantity: 450 kW

2. Remaining Payments:

All payments and penalties other than the Early Exit Fee will be made in one net payment or charge, as applicable, after the conclusion of the Capability Period. A sample calculation can be found on the BQDM website: https://conedbqdmauction.com/

The net payment or charge will be:

(Reservation Payment) + (Bonus Payment) + (Performance Payment) – (Capacity Non-Availability Penalty)

Con Edison will make any Payments to DR Providers by November 20 for each year. Any net amount that is owed Con Edison must be paid within 5 business days of issuance of a bill.

Payments and Penalties are based on the Annual Performance Factor which represents the actual performance relative to the Portfolio Quantity and is expressed as a percent value. The **Annual Performance Factor** is the average of all of the Event Performance Factors. If there are no events the Annual Performance Factor is equal to the Test Performance Factor. All performance factors are measured on a portfolio basis for each DR Provider for each DR Product.

The **Event** or **Test Performance Factor** is the average hourly kW Load Relief provided during the mandatory part of an event or test divided by the total amount of the Portfolio Quantity. It must be between 0 and 1.

- **Reservation Payment**
  Reservation Payment = (Annual Performance Factor) x (Portfolio Quantity) x (Clearing Price)
- **Bonus Payment**
  If a DR Provider has an Annual Performance Factor of 100% for a DR Product it will receive a 20% bonus on the reservation payment.
  Bonus Payment = (Portfolio Quantity) × (Clearing Price) × (20%)
- **Performance Payment**
  A Performance Payment of $5/kWh is applied for actual load reduction (up to a limit as defined in the Program Agreement Addendum) during every event or test.
- **Performance Penalty**

The penalty for under performance is based on the Annual Performance Factor. There is no penalty if the Annual Performance Factor is at least 85%. The Performance Penalty for performance below 85% is:

Performance Penalty = (0.85 - Annual Performance Factor) × (Portfolio Quantity) × (Clearing Price)

1. Timeline

	2016				2017								
	June	July	August	September - December	January	February	March	April	May	June - September	October	November	December
Events and Trainings	· BQDM DR Introductory Forum (June 6th) · Introductory webinar (June 22nd)	· Introductory webinar (July 7) · Auction platform training (July 13 and 19)			· Introductory webinar (date TBD)								
DR Auctions and Enrollment	· Auction pre-qualification opens (June 6th)	· Auction pre-qualification closes (July 20) · 2017 DR Auction (July 27) · 2018 DR Auction (July 28)	· Auction clearing price and awards annouced (August 1) · Signed aggregator contracts due 5 business days from award notification			· Aggregators notify Con Edison of Enrollment Deficiency amounts (February 15)	· Enrollment opens (March 1) · Enrollment Attachment requests due (March 8) · Enrollment additions announced (March 15)	· BQDM DR Enrollment Closes - ALL applications and permitting due (April 2)					
DR Participation							· Con Edison to notify market of if Enrollment Attachment is allowed (March 1)	· Con Edison communicating interval meter installation deadline (April 2)	· 2017 BQDM DR Capability Period starts (May 1)	· 2017 BQDM DR Capability Period ends (September 30)			
Payments and Penalties						· Aggregator Enrollment Deficiency payments due (February 21)						· 2017 DR payments due to aggregators and customers (November 20)	· 2017 DR penalties due to Con Edison

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