Stan Faryniarz, CEP

Principal Consultant

Mr. Faryniarz is a member of La Capra Associates' senior project management team and served for a number of years on its Board of Directors. He has consulted on cost allocation and rate design, pricing and preparing special contracts, renewable resource development, distributed energy resources ratemaking and policy, power procurement and transactions, economic and financial analyses and strategic matters for a wide variety of energy industry and other clients in New England, the U.S. and Canada, concentrating in particular on public and investor-owned power systems and industrial clients. Mr. Faryniarz has an extensive range of skills and experience in cost allocation and rate design, contract pricing and negotiations, the energy markets in the northeastern U.S. control areas, economic and financial analyses, regulatory, government and consumer relations for utilities, customers and industry groups, economic impact studies and studies for clients undergoing legislative or regulatory scrutiny.

He holds a BA in Economics and MPA (Finance and Managerial Economics concentration) from the University of Vermont, and the Certified Energy Procurement (CEP) Professional designation from the Association of Energy Engineers.

PROFESSIONAL EXPERIENCE

Cost Allocation & Rate Design

- Assisted the Manitoba Public Utilities Board (PUB) with a comprehensive review of and report on the most recently filed Manitoba Hydro cost of service study (COSS) and rate design.
- Leading a team on behalf of the Kauai (HI) Island Utility Cooperative (KIUC), in developing an LED streetlight tariff (Transmittal 2015-03, approved), and a statutorily-driven Community-Based Renewable Energy (CBRE) tariff (approval pending, Docket 2015-0382). The team has also prepared a rate case for potential filing in 2016 if KIUC's revenue decoupling plan is not approved, and we have prepared a comprehensive rate redesign intended to help KIUC integrate and fairly compensate significant distributed energy resources (DER, mostly customer-sited solar) into its system. Assisting KIUC with participation on rate design issues in a statewide HI PUC proceeding on further integration of DER into the Hawaii island grids (Docket 2014-0192).
- For the Stowe (VT) Electric Department, led a team that prepared a load research study compiled from smart meter data, developed custom cost allocators using this load research, prepared a comprehensive allocated cost of service study (ACOSS) reflecting customer class consolidation, and a voluntary seasonal time-of-use (TOU) and critical peak pricing (CPP) rate design. Offered supporting testimony before the Vermont Public Service Board (Docket 8463) and gained approval from the VT Department of Public Service (DPS) and PSB without changes.
- Testified before the Utah Public Service Commission in Docket 13-035-184, on behalf of the Utah Division of Public Utilities (DPU), regarding the rate design and implementation proposals, and a proposal for a new net metering charge, by Rocky Mountain Power.
- Prepared and sponsored in testimony over a dozen cost of service, cost allocation, rate design, special contracts, and three demand elasticity studies for numerous electric and water companies in Maine, Pennsylvania, Rhode Island, Utah and Vermont.

- For Amtrak, developed special contracts and tariffs across 3 service territories from Connecticut Light & Power to Narragansett Electric Company (RI PUC Docket 2867) to Boston Edison Company when Amtrak electrified its north end high speed rail system, which reflected the unique characteristics of Amtrak's moving train loads. More recently, negotiated appropriately-priced special contracts in the Baltimore Gas & Electric territory for distributed generation dedicated to serving Amtrak. Advised Amtrak with a now-expired load retention special contract, and assisted with negotiations with Philadelphia Electric Company on preservation of conjunctive demand billing for Amtrak traction power deliveries which lead to a stipulated settlement. Recently assisted Amtrak as an expert witness in Pennsylvania PUC Docket R-2015-2469275 (Pennsylvania Power & Light Rate Case) leading to a stipulated resolution. Currently negotiating changes to a pancaked transmission tariff arrangement Amtrak is under in PJM.
- For Washington (VT) Electric Cooperative (VT PSB Dockets 7427 & 7575); completed, successfully defended and obtained Public Service Board approval for a contested long-term marginal cost-based rate design. Prepared for filing Open Access Distribution and Transmission Tariffs applicable to distributed generation and renewable power projects.
- For the Vermont Public Power Supply Authority, led a team that trained its in-house rate analysts using proprietary Daymark Energy Advisors cost allocation, billing curve and rate design models. Assisted VPPSA with preparation for filing of an embedded cost allocation and marginal cost-based rate design involving several of its systems. These have included a unique special contract design for a ski area that encourages minimization of demand during system coincident peak conditions, a design for one system which recognizes the requirement to integrate output from a hydro station approximately equivalent to the load for the entire system, and an electric vehicle charging rate.
- For Littleton (NH) and Woodsville (NH) Water & Light Departments, assisted with proforma rate decreases occasioned by more economic power supply arrangements we arranged, and reviewed and made recommendations on in-house allocated cost of service studies to guide appropriate rate design.
- For the Town of New Shoreham (RI), in a Block Island Power Company rate case (RI PUC Docket 3655), prepared testimony that showed how rates and demand response could be integrated, together with appropriate system planning, to forestall the need for significant investment in additional diesel generation on Block Island.
- For Belmont (MA) Municipal Electric Department, oversaw first draft time-of-use and seasonal cost allocation study and rate design, which led to eventual seasonal rates for all customers, and inclining block rates for residential customers. Advised the Municipal Light Advisory Board on various time-of-use rate designs, including critical peak pricing (CPP) and real-time pricing (RTP) approaches.
- For Bar Harbor (ME) Water Company, prepared an allocated cost of service study and rate design that phases from declining block to uniform volumetric rates and reduced allowances for year-round and seasonal customer classes.
- For a large industrial customer intervener in an Aqua Maine Water Company rate case (Maine PUC Docket 2010-72), reviewed company workpapers and testimony, and supported successful negotiations that led to modifications in the Aqua Maine design to more fairly reflect the capacity costs of serving that largest customer on the system, without having to produce prefiled testimony.
- For the Pennsylvania Office of Consumer Advocate (York Water Company v Pennsylvania PUC, Dockets R-00016236 & R-00016236C0001-C0006), filed testimony supporting changes to the York Water Company excess capacity allocations to reflect a more equitable revenue requirement responsibility for and better price signals to the residential class.

Additional Experience

Mr. Faryniarz also has expertise in the areas of Power Procurement & Transactions, Portfolio Management, Commerce and Planning, Project Finance and Valuation.

EMPLOYMENT HISTORY

Daymark Energy Advisors (*formerly La Capra Associates, Inc.)* — Boston, MA
Principal Consultant — *2015 – Present*
Consultant, Managing Consultant — *1999 – 2014*

Decisions Economics LLC — Underhill, VT
President and Consultant — *1994 – 1999*

Weil & Howe, Inc. — **Augusta, ME**
Consultant — *1990 – 1999*

Vermont Department of Public Service — **Montpelier, VT**
Special Counsel for Financial Analysis — *1986 – 1990*

EDUCATION

Association of Energy Engineers — Atlanta, GA
Certified Energy Procurement (CEP) Professional — 2008

University of Vermont — Burlington, VT
Masters in Public Administration with extensive — 1986
M.B.A. curriculum in Finance, Managerial Economics

Michigan State University — East Lansing, MI
NARUC Graduate Studies Program in Regulatory Economics — *1986*

University of Vermont — Burlington, VT
B.A. in Economics, Cum Laude with Departmental Honors — *1982*
Omicron Delta Epsilon, International Economics Honor Society

Selected Testimony of Stan Faryniarz, CEP

- **Before the Maine Public Utilities Commission**

  On behalf of Camden & Rockland Water Company et al.

  - Docket No. 93-145 Petition of Camden & Rockland Water Company et al. for a Proposed Increase in Rates (Rate Case, Rate Design)

- **Before the Maryland Public Service Commission**

  On behalf of the National Railroad Passenger Corporation (AMTRAK)

  - Case No. 9173 Phase II In the Matter of the Current and Future Financial Condition of Baltimore Gas and Electric Company (Merger)

- **Before the Nova Scotia Utilities and Review Board**

  - Docket No. ____ Investigation into Non-utility generation resources and U.S. PURPA Qualifying Facility policies (PURPA).

- **Before the Pennsylvania Public Utility Commission**

  On behalf of the Pennsylvania Office of Consumer Advocate

  - Dockets R-00016236 & R-00016236C0001-C0006 York Water Company v Pennsylvania PUC (Rate Case & Rate Design)

  On behalf of the National Railroad Passenger Corporation (AMTRAK)

  - Docket No. P-2008-2060309 Petition of the PPL Electric Utilities Corporation for Approval of a Default Service Program and Procurement Plan for the Period January 1, 2011 Through May 31, 2014 (Default Power Supply Service)
  - Docket A-2008-2078319 Application of Safe Harbor Water Power Corporation Pursuant to Section 1102(a)(2) of the Pennsylvania Public Utility Code Authorizing Safe Harbor Water Power Corporation to Abandon Public Service Authorized by a Certificate of Public Convenience (Generation Service)
  - Docket No. R-2015-2469275 Pennsylvania Public Utility Commission v. PPL Electric Utilities Corporation (Rate Case)
  - Docket No. P-2015-2474714 Petition of PPL Electric Utilities Corporation for Waiver of the Distribution System Improvement Charge Cap of 5% of Billed Revenues (Rate Case)

- **Before the <u>Rhode Island Public Utility Commission</u>**

  On behalf of the National Railroad Passenger Corporation (AMTRAK)

  - Docket No. 2867 Rhode Island Public Utility Commission vs Narragansett Electric Company (Rate Design)

  On behalf of the Town of New Shoreham

  - Docket No. 2867 Rhode Island Public Utility Commission vs Block Island Power Company (IRP, Rate Design)

- **Before the <u>Utah Public Service Commission</u>**

  On behalf of the Utah Division of Public Utilities

  - Docket 13-035-184 In the Matter of the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations (NEM Rate Design)

- **Before the <u>Vermont Public Service Board</u>**

  On behalf of the Vermont Department of Public Service

  - Docket No. 4949 Petition of Emerson Falls Hydroelectric for 30-year power sales contract pursuant to Rule 4.100 (PURPA QF)
  - Docket No. 4964 Petition of Bio-Energy Corporation for 30-year power sales contract pursuant to Rule 4.100 (PURPA QF)
  - Docket No. 5109 Agreement for sale of electricity between VPX Inc. and Vermont Marble Power Company pursuant to Rule 4.100 (PURPA QF)
  - Docket No. 5168 Petition of Comtu Falls Hydro for Long-term Levelized Rates pursuant to Rule 4.100 (PURPA QF)
  - Docket No. 5177 Rule 4.100 Small Power Production Rates filed by the Vermont Department of Public Service (PURPA QF Avoided Costs)
  - Docket No. 5179 Petition of East Georgia Cogeneration re: Approval of Levelized Rates pursuant to Rule 4.100 and Issuance of a Certificate of Public Good pursuant to 30 V.S.A. Ss 248 (PURPA QF)
  - Docket No. 5181 Petition of First Energy Associates vs VPX Inc. re: Decker Energy Letter of Intent with VPX (PURPA QF)
  - Docket No. 5193 Petition of Vermont Department of Public Service requesting deletion of the decremental pricing provision contained in the contract between VPX Inc. and Missisquoi Associates approved in Docket 5106 (PURPA QF)
  - Docket No. 5233 Petition of Great Falls Hydroelectric for 30-year levelized rates pursuant to Rule 4.100 (PURPA QF)
  - Docket No. 5270 Investigation into Least Cost Investments, Energy Efficiency, Conservation and Management of the Demand for Energy (IRP)
  - Docket No. 5298 Investigation into Fee Schedules for VPX, Inc. (Rate Case)
  - Docket No. 5411 Investigation into the Tariff Filing for VPX Inc. (Rate Case)

On behalf of Utilities

- Docket No. 6315 Investigation into the Tariff Filing Washington Electric Cooperative for a 3.8% Rate Increase (Rate Case)
- Docket No. 6328 Investigation into the Tariff Filing Washington Electric Cooperative re: Proposed Rate Design Changes (Rate Design)
- Docket No. 6924 Joint Petition by Washington Electric Cooperative, Inc. ("WEC"), Vermont Electric Power Company, Inc. ("VELCO"), Citizens Communications Corporation ("CZN"), and Vermont Electric Cooperative, Inc. ("VEC") for a Certificate of Public Good pursuant to 30 V.S.A. § 248 authorizing: (1) WEC to construct an electric generation station in Coventry, Vermont; WEC & VELCO to make improvements to the Irasburg substation; (3) WEC, VEC & CZN to construct 46 KV transmission lines in Coventry and Irasburg, Vermont, including provisions for distribution system construction by CZN and VEC. (Certificate of Public Good)
- Docket No. 6925 Joint Petition by the Washington Electric Cooperative ("WEC") and Coventry Clean Energy Corporation ("CCEC") for (1) a certificate of public good authorizing CCEC to operate as a corporation that generates and transmits electricity; (2) authorization of WEC to have a 100% ownership interest in CCEC; (3) approval for CCEC to sell all its generation to WEC; (4) approval of WEC's promissory note to the Rural Utilities Service; and (5) approval of CCEC's promissory note to WEC. (Certificate of Public Good)
- Docket No. ____ Petition by Washington Electric Cooperative, Inc. ("WEC"), for (1) a Certificate of Public Public Good pursuant to 30 V.S.A. § 248(j) authorizing the Coventry Project Expansion; and (2) approval of WEC's promissory note to the National Rural Utilities Cooperative Finance Corporation (CFC) pursuant to 30 V.S.A. § 108 to finance the Coventry Project Expansion. (Certificate of Public Good)
- Docket No. ____ Petition by Washington Electric Cooperative, Inc. ("WEC"), for (1) a Certificate of Public Public Good pursuant to 30 V.S.A. § 248(j) authorizing the Second Coventry Project Expansion; and (2) approval of WEC's promissory note to the Rural Utilities Service pursuant to 30 V.S.A. § 108 to finance the Second Coventry Project Expansion. (Certificate of Public Good)
- Docket No. 7575 Petition of Washington Electric Cooperative ("WEC"), for approval of rate design changes and a change in rate schedules pursuant to 30 V.S.A. § 225 (Rate Design)
- Docket No. 8463 Petition of Stowe Electric Department For Approval of Its 2015 Rate Design and Tariff Amendments (Rate Design)

- **Before the <u>Bennington Vermont Family Court</u>**

  - Docket No. F182-6-93BnDmd Livingston vs. Livingston, Valuation of Environmental Power Corporation for Plaintiff (Valuation)

- **Before the Joint Hearing of the <u>Vermont House Commerce and Senate Finance Committee</u>**

  - 1988, Valuation of the Vermont Electric Power Company (VELCO) (Valuation)

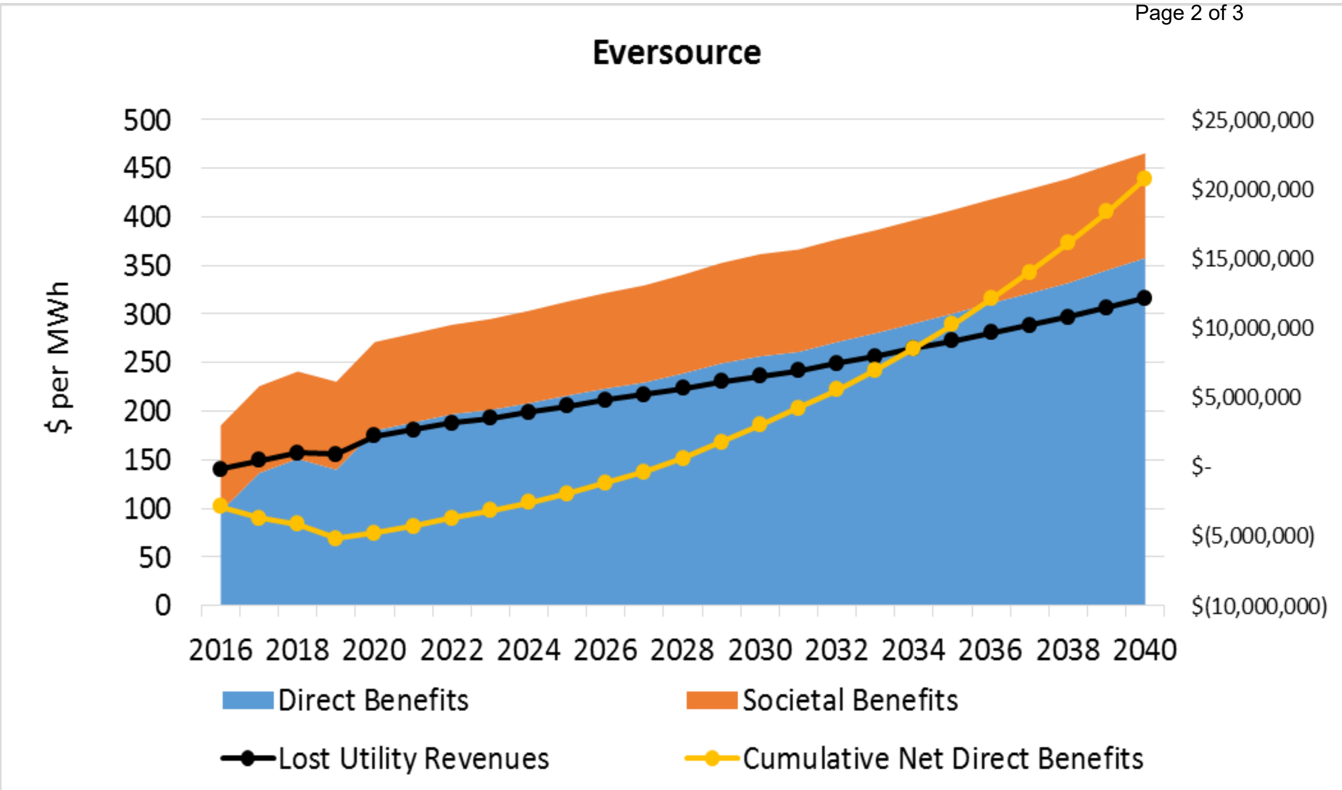
STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION
Docket DE 16-576
Development of New Alternative Net Metering Tariffs and/or
Other Regulatory Mechanisms and Tariffs for Customer-Generators
Response to Commission Staff's Data Requests to The Alliance for Solar Choice - Set 1
Request Received: November 4, 2016
Response Date: November 17, 2016

Request No. Staff 1-3
Witness: R. Thomas Beach

REQUEST:
Throughout the Direct Testimony of R. Thomas Beach, beginning on p. iii, he refers to long-term benefits, including to non-participants in NEM. Please indicate: (a) when cumulative benefits are likely to exceed cumulative costs over the 25-year horizon, and (b) whether this time horizon during which, for some time, cumulative costs exceed cumulative benefits, presents intergenerational inequities to non-participants.

RESPONSE:
Mr. Beach's cost-benefit analysis compared long-term costs and benefits, but did not analyze how the elements accumulate over time (i.e. on an annual basis). TASC has now performed the year-by-year analysis requested, for the utilities' residential markets, and presents the results in the figures below. These results show that the timing of the direct utility costs and benefits are very similar, such that there are no significant intergenerational equity issues. If societal benefits are considered, the benefits exceed the costs in all years. Because the benefits exceed the costs by significantly more in the commercial market than the residential, this conclusion holds for commercial as well. In the residential market, the cumulative benefits are likely to exceed cumulative costs beginning in 2028 for Eversource, as shown on the Eversource figure.

The workpapers for these figures are attached in the file "Year by Year Benefits.xlsx."


Eversource
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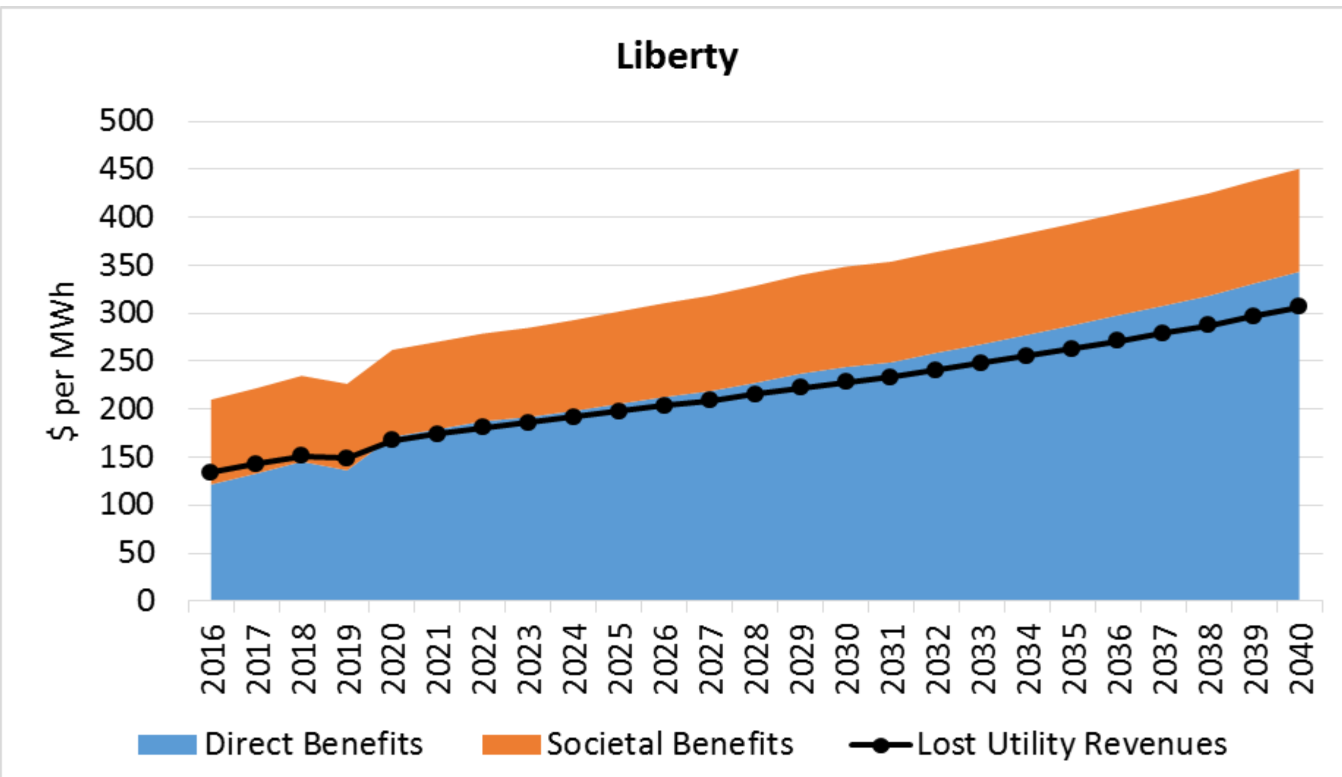
2016 2018 2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Direct Benefits
Societal Benefits
Lost Utility Revenues
Cumulative Net Direct Benefits


Liberty
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250
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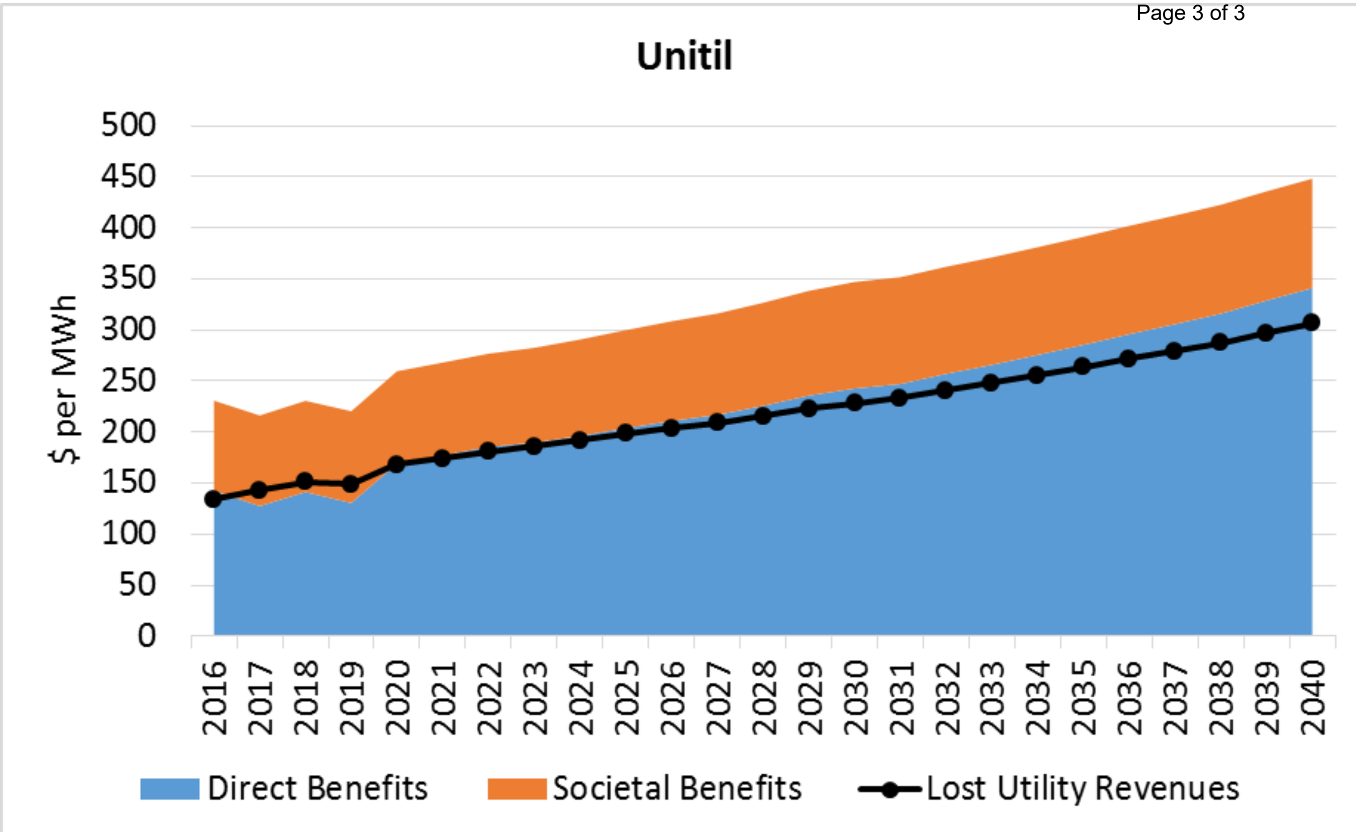
$ per MWh
2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040
Direct Benefits
Societal Benefits
Lost Utility Revenues


Unitil
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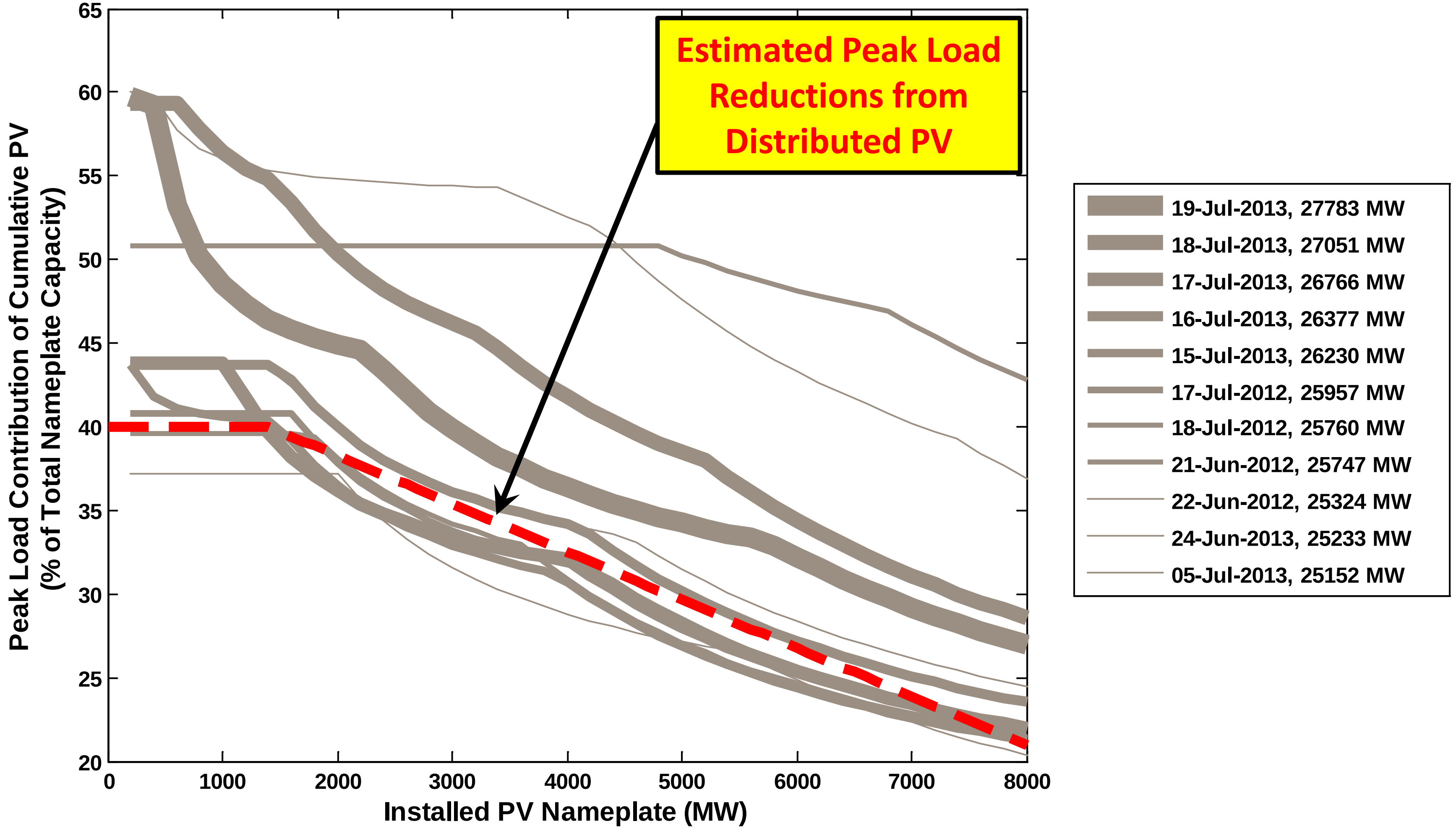
Direct Benefits
Societal Benefits
Lost Utility Revenues

Distributed PV's Estimated Peak Load Reductions

Assumed Load Reduction Considers a Variety of Peak Load Shapes



STAN FARYNIARZ
Appendix SF-4
Excerpt from 2016 NARUC Manual on Distributed Energy Rate Design and Compensation

time-variant rates. However, a user of this document may wish to mix and match the traditional types of rate designs, such as a TOU, with options in either the rate design or the compensation sections. Examples of this can be found in California and Hawaii, which are moving toward default TOU for customers in response to the increased amounts of solar PV in their states. The right mix of options is best determined by the particular jurisdiction.

1. Demand Charges

This rate design method charges customers based on their rate of usage, measured in KW, rather than total volume of usage (i.e., kWh). Regulators have used demand charges historically to recover generation capacity, transmission capacity, or distribution system costs from customers, primarily C&I customers, and some also have experience with using demand on a class-wide basis for cost allocation.

Demand charges have increased in popularity in a relatively short period of time. The majority of the applications being discussed and proposed across the nation feature demand charges as mandatory or opt-out rates for residential and small commercial customers. This interest has largely been driven by DER's potential effect on utility cost recovery, since kW-based charges cannot be offset by NEM rates or similar programs, as well as by greater adoption of AMI and enabling technology.

As of the writing of this Manual, very little empirical data exist on impacts of demand charges on residential and small commercial customers, and no investor-owned utility currently uses a mandatory, or opt-out, demand charge, although several have proposed them.[126] Demand charges themselves can represent significant cost shifting, so regulators should be extra cautious in their development and implementation, ensuring they understand the implications of the charges for their jurisdictions and the rate's advantages (and

126 Rocky Mountain Institute, "A Review of Alternative Rate Designs" (Rocky Mountain Institute, Boulder, CO 2016).

disadvantages) over alternatives.[127,128]

Demand charges can be structured many different ways and they vary widely in their purpose, in their effect, and in the price signal they send.[129] Therefore, when considering implementing a demand charge, regulators must be comfortable with and clear on the costs they would like to recover, the price signals they would like to send, which principles of rate design they emphasize and why, and their plan for implementation.

In general, customers' understanding of, and their ability to react to, demand charges represents a challenge.[130] Opponents and proponents of demand charges both agree that significant customer education is key if implementing these rates and that regulators should employ pilot programs or shadow billing over a multi-year rollout.[131]

a. Historical Use of Demand Charges

Demand charges have long been used in commercial and industrial customer class rates, as these customers are generally more sophisticated, with better load factors and control of their usage.[132] Though there has been some experience with opt-in residential programs, historically, demand charges have not been applied to other customer classes.

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127 Jim Lazar, "Use Great Caution in Design of Residential Demand Charges" (Regulatory Assistance Project, Montpelier, VT, 2016), 13.

128 An alternative regulators should examine is satisfying the temporal changes in cost causation through TOU charges (with decoupling if revenue erosion or cost recovery is a serious issue). TOU charges may better reflect the cost structure of electricity for a majority of demand costs on a system, especially compared with non-coincident demand charges.

129 Since the increased interest in these rates is new, and due to lack of data and experience concerning residential and small commercial demand charges, this section of the Manual is relatively longer to provide additional information for regulators.

130 Paul Chernick, *et al.*, "Charge without a Cause? Assessing Electric Utility Demand Charges on Small Customers" (Electricity Policy, Portland, OR, August 2016).

131 EEI Primer, 11; Solar Energy Industries Association, et al., "Rate Design"; Ryan Hledik, "The Top 10 Questions about Demand Charges" (presentation at the EUCI Residential Demand Charges Symposium, Denver, CO, May 2015).

132 Ahmad Faruqui, *et al.*, "Curating the Future of Rate Design for Residential Customer" (Electricity Policy, Portland, OR, July 2016).

When used as a billing determinant for customers, demand charges are another line item cost included on a utility bill—in addition to fixed and energy costs, which make up a utility's revenue requirement. These charges endeavor to measure the "size of the pipe," or capacity needs of a customer, and in their purest form endeavor to measure a customer's contribution to the system's various peaks, and thus—to the extent that these costs are not fixed—the driver of the system's size and the resulting costs.

Utilities calculate demand charges as the rate at which a customer draws from the system, measured in kW, during a certain time period (e.g., during a coincident peak of the system, over all afternoon hours, over a seasonal period, during all hours) using the single highest peak of instantaneous demand, or combination of multiple peaks; or, more often, by using the customer's usage averaged over one or more measurement intervals (i.e., usually 15, 30, or 60 minutes) during the period in question.[133] A measurement interval is often used so that short-term demand spikes have less of an effect than sustained higher levels of usage.[134]

Even though annual demand on a class-wide basis is most often used to allocate costs,[135] when proposed or used in a residential context, demand charges are often included as a percentage of the delivery portion of a customer's bill and are measured and applied on a relatively more frequent basis, usually monthly, to increase bill stability and allow customers to react more frequently to price signals.[136] Utilities sometimes add a mechanism called a "ratchet," described further below. In some foreign countries, some utilities use pre-set demand levels, called "ex ante,"[137] by Rocky Mountain Institute (RMI) or

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133 Rocky Mountain Institute, "Review of Alternative Rate Designs."

134 Hledik, "Top 10 Questions," 13 ("precision" vs. customer bill stability).

135 Migden-Ostrander and Shenot, "Designing Tariffs," 29 ("It could even be argued that to the extent that interval data is not used as the basis for allocating demand costs in the cost-of-service study, rates should not be designed using data that conflicts with the data used to allocate the costs to be recovered in those rates.").

136 Rocky Mountain Institute, "Review of Alternative Rate Designs."

137 As opposed to the demand charges described above, which RMI calls "ex post."

a demand subscription, in which a circuit breaker is tripped, demand limited, or extra fees assigned if customers go over a pre-set kW level.

If the rates are properly understood by customers and loads can be shifted to outside the measured time period, then these demand charges can incentivize customers to "shave" their peaks or shift usage to another time, and with coincident rates, reduce the overall system peak. But how, when, and how often this demand is calculated can vary in practice and jurisdictions.

b. Rationale For and Against Demand Charges

Proponents of demand charges outline several reasons for the rates. The Edison Electric Institute advocates for demand charges, saying the "primary function of the demand charge is to accurately convey the cost structure of electricity to customers so that they can make informed decisions about how much power to consume and at what time."[138]

Other advocates state that the demand charges better reflect cost causation, or the driver of a utilities cost, than a volumetric rate does. Many argue this is because a utility's generation capac-

Some Examples of Demand Charges

- Arizona Public Service recovers for generation capacity, transmission, and distribution charges on an opt-in basis combined with a seasonal TOU rate. A customer's demand is calculated monthly as usage divided over a one-hour interval coincident with the highest seven hours of system peak. It has two seasons, with the summer peak running from May through October.
- Burbank Water & Power's Basic Service Rate recovers a preset level for a service size charge, which is the customer's service drop and last transformer based on the maximum possible demand.
- ComEd uses a customer's coincident demand to calculate a volumetric capacity charge: the following year's generation and transmission capacity charges for a residential real-time pricing program are calculated by taking whichever is higher, the customer's highest electrical demand coincident with the five highest hours of overall system demand in PJM or the five highest hours on the local utility's system. The average is then adjusted and used to calculate the volumetric charge for the next year.

138 EEI Primer, 6-7 ("Whether customers reduce demand on response to a demand charge is a secondary benefit.").

ity and distribution costs do not increase and decrease with changes in the total volume of usage.[139] To many proponents, the short-run costs of the distribution system are fixed in nature, and as such these "sunk" costs should be split among customers in the same rate class based on their demand, regardless if their demand contributes to a system or local peak.[140] Utilities and other advocates of demand charges generally prioritize revenue recovery and stability in rate design by orienting the cost allocation and rate design process to look backward in time to recover the embedded cost that the utility prudently spent to provide service. Other proponents argue that low load factors, regardless of whether they contribute to a system or local peak, result in higher costs to the utility.[141]

Additionally, advocates argue that demand charges are a rate the industry is familiar with, and therefore are a well-tested model with a small learning curve.[142]

Theoretically, one of the main advantages of demand charges seems to be the greater revenue certainty, especially for certain forms of non-coincident rates, which improves the chances for full recovery of a utility's authorized return. This is mainly due to the costs being recovered based on individual peaks, which are relatively inelastic as compared with the overall volume of usage, which can vary greatly from year-to-year, largely due to weather, energy efficiencies and building standards, and customer behavioral changes.[143] In this way, these rates can reduce risk for the utility. Further, in line with utility desire for improved revenue stability, some advocates call demand charges a good "middle ground" or a compromise between higher fixed charges and pure

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139 Faruqui, *et al.*, "Curating the Future."

140 *Id.*; Leland Snook and Meghan Grabel, "There and Back Again" (*Public Utilities Fortnightly*, Reston, VA, November 2015), 48–49 ("almost 70% of the costs to serve APS's residential customers are fixed infrastructure costs").

141 Southern Company, "Comments on Draft NARUC *Manual on DER Compensation*" at 5 (September 2, 2016).

142 Hledik, "Top 10 Questions," 13.

143 Faruqui, et al., "Curating the Future."

kWh-volumetric pricing.[144]

Demand charges also have the potential to be an avenue to reduce the cost shifting illustrated in historical rates concerning DG customers (i.e., NEM). Some utilities have specifically proposed using demand charges to replace volumetric charges in distribution system cost recovery, leaving NEM rates to affect only the energy portion. Since the NEM rates usually provide a credit against consumption on a volumetric basis, charging a residential customer its distribution costs through KW-based rates eliminates the possibility that NEM compensation is shifting those costs. This practice, however, would not compensate nor charge DER customers for any benefits, or additional costs, they represent to the grid.

However, as opponents argue and proponents agree, there are many unknowns and much uncertainty surrounding the use of demand charges on classes other than C&I—mainly regarding customer impacts. Empirical data on the impacts as well as customer acceptance and responses to residential and small commercial demand charges are insufficient.[145] In a review of residential demand charge rate designs, RMI identified only 25 demand charge rates offered to residential customers, and none of them were large investor-owned utilities implementing mandatory demand charges for residential or small commercial customers.[146]

Opponents urge great caution in using these rates, as they state severe cost shifting can occur.[147] They also generally state that the primary function of demand charges, namely temporal differences in cost causation, can be better conveyed through other mechanisms. These parties assert traditional demand charges overcharge low-use customers, which tend to have lower load factors

144 Jeff Zethmayr, "Bill Effects of Demand-Based Rates on Commonwealth Edison Residential Customers" (Electricity Policy, Portland, OR, July 2016).

145 Rocky Mountain Institute, "Review of Alternative Rate Designs"; Hledik, "Top 10 Questions"; Solar Energy Industries Association, "Rate Design."

146 Rocky Mountain Institute, "Review of Alternative Rate Designs," 57.

147 Lazar, "Use Great Caution."

but ones that often peak at times that do not contribute to system peaks. This stems from the fact that residential customers are much more diverse in their usage and thus tend to share capacity, especially multi-family customers, whose demand is met in the aggregate and not on an individualized basis.[148]

Opponents tend to generally approach rate design and cost recovery not from a backward-looking orientation that seeks to recover the sunk embedded costs already spent, but from a forward-looking marginal cost perspective that sees all costs as variable, but on a short-run and a long-run basis. Proponents agree these principles are theoretically sound.[149] These topics are addressed other places in this Manual and in the NARUC *Electric Utility Cost Allocation Manual.*

Opponents also argue that demand rates do not have an actionable price signal and are confusing to customers. Indeed, economists, such as UC Berkeley Professor Severin Borenstein, state, "It is unclear why demand charges still exist."[150] They assert the charges are poorly understood by customers as compared with volumetric rates, and therefore struggle to adequately convey an understandable price signal. Even if they did better reflect utility costs and represent a clear price signal, demand charge signals are most likely not sufficiently actionable for customers without demand limiters, expensive technology, or drastic behavioral changes.[151] Thus, lower-income customers may be disproportionally affected as they may have less control over peak demand usage. This signal could be further obfuscated as there is a smaller margin for customer error; higher bills can be earned through a shorter time frame of a lapse of attention (e.g., too many appliances on at once) or a one-off

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148 *Id.;* Lazar and Gonzalez, "Smart Rate Design"; Chernick, et al., "Charge without a Cause?"; Coley Girouard, "Do Demand Charges Make Sense for Residential Customers?" (Advanced Energy Economy: Washington, D.C., June 21, 2016), http://blog.aee.net/do-demand-charges-make-sense-for-residential-customers.

149 Edison Electric Institute, "Comments of the Edison Electric Institute on the National Association of Regulatory Utility Commissioners' Draft Manual on Distributed Energy Resources Compensation" (Edison Electric Institute, Washington, D.C., September 2, 2016), 9.

150 Borenstein, "Economics of Fixed Cost Recovery," 16.

151 Chernick, et al., "Charge without a Cause?"

event such as a house guest, which can also result in the possibility of higher bill volatility from month to month.[152] Further, to the extent that demand charge structures may encourage reduction in peak (depending on how peak is defined), it potentially lacks an adequate conservation signal to reduce usage.

Importantly, many parties on all sides of the issue seem to recognize the potential for using demand charges sparingly (e.g., to represent a dollar or two on an average bill for customer-specific, local costs, such as the last transformer) and when measuring demand coincident with system peaks,[153] but the number of opponents quickly grow as the utilities begin to depend more and more on these rates for recovering their distribution system costs.

As discussed below, the demand charge success will be largely driven by the fine details of the structure imposed—ultimately who pays what portion of the charge and the parity of that allocation.

c. Considerations in Demand Charges

As with many of the various methodologies available to regulators, the implications of the use of demand charges depend greatly on the details of the design and implementation of the charge. Once a jurisdiction has the technology to meter on a demand or interval basis, then regulators can examine demand charges and explore the purpose, price signals, and relative emphasis of rate design principles they could then enshrine in these rates.[154] The effects of a customer's demand seem to be clearer for generation capacity and transmission, which can be tied to larger peaks like the entire system, but when talking about the distribution system, the effects of a customer's demand on the system could be less clear. Furthermore, as Borenstein states, "the single

152 Rocky Mountain Institute, "Review of Alternative Rate Designs."

153 Lazar and Gonzalez, "Smart Rate Design."

154 Lazar's three-part rates found in Regulatory Assistance Project's materials might be a good starting point. Once a path is decided, it should be compared with alternatives. For instance, Lazar points out that compared with large demand charges, time-varying rates result in more equitable cost allocation, reduce bill volatility, and improve customer understanding. See Lazar, "Use Great Caution," 13.

highest consumption hour of the billing period is not the only, and may not even be the primary, determinant of the customer's overall contribution to the need for generation, transmission and distribution capacity."[155]

Unfortunately, analyzing the implications of the various forms and magnitude (or the level of revenue, or cost recovery components, being sought through the charge) of demand charges is currently difficult. Thus, regulators should be wary of relying on unsupported benefits as evidence and be cautious when plausible harm may represent itself. More data should be available in the future as several utilities have submitted proposals for mandatory and opt-out demand charges to regulators and legislators. In the meantime, regulators should also be cautious of proponents using the outcomes from opt-in tariffs as evidence or proxy for mandatory or opt-out tariffs, as the historical rates can suffer from self-selection bias and their customers have been reported to be significantly larger than average.[156]

Both increasing adoption of DER and moving beyond traditional, two-part (volumetric and fixed charge, or straight fixed variable) rates should require regulators to increase their visibility into, and their planning for, the relevant distribution system and the effects of individual customer usage patterns on its different levels. As discussed, this requirement is embodied in the changing landscape for electricity in the country. As such, regulators may find that their legacy processes, such as allocating cost by demand, do not easily translate into support for charges on an individual basis and that changes might be required.

It is relatively clear how demand charges benefit utilities with revenue stability. On the customer side, if done appropriately and properly understood, a rate's price signal could help contribute proportionally to reducing the peaks, which should lead to savings for all customers on the system in the long run as generation becomes less expensive and if the regulator can properly incorpo-

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155 Borenstein, "Economics of Fixed Cost Recovery," 16.

156 Hledik, "Top 10 Questions," 6.

rate any distribution savings in new rate proceedings. Ideally, any demand charges regulators implement should have clear, transparent support detailing the relevant peaks they are targeting to reduce; the costs caused by the individual's usage contributing to that peak; and how they will pass on the system savings, if any, resulting from demand reductions to customers, if not already automatic. These elements should come naturally from a more detailed look into the distribution systems and the pressure DER can place on them and the benefits DER can provide.

Demand charges' relation to cost causation for distribution systems can present a challenge. Whether a specific demand charge better aligns bill impacts with cost causation depends greatly on the structure of the charge and the jurisdiction's unique legacy processes and physical grid. The question becomes, in that unique situation, what effects an individual's usage, both rate and timing, has on the costs of the various components of the grid, and subsequently what is the best way of presenting those costs to the customer. In general, regulators should be wary of arguments, for or against, that conflate more efficient economic signals and alignment with cost causation with an individual's non-coincident peak maximum demand, unless backed up with detailed evidence and testimony.[157] Regulators may find, as some opponents have argued, that lower load factors result in higher costs for the utility, regardless of when the peaks occur.[158] However, it is questionable whether demand not aligned with a specific peak could drive distribution costs beyond their immediate surroundings, and if they do, whether it would be prudent to charge customers for it.

Regulators should remember that, to a certain extent, intra-class subsidies are unavoidable as, for example, it often costs more to deliver power on a

157 Discussed more below.

158 It certainly is understandable why, from a utility's perspective, a low-load-factor customer could represent "money left on the table" if it is paying volumetric rates. Conceivably it could be paying more for distribution if charged by peak than volume. But for this discussion it is relevant only to the extent that a load factor (without factoring in any temporal considerations) drives costs. This seems to be unlikely, and to the extent it would be true, would be coincidental.

per customer and per demand basis in rural areas compared with suburban or urban areas. Regulators should endeavor to ensure that any move to demand charges does not represent an undue burden on the customers that are, on an individual basis, actually the lowest cost to serve (e.g., multifamily customers in dense urban areas), nor burden the customers that are most expensive with costs that have historically been socialized for policy reasons (e.g., large, single-family rural customers).

Ultimately, the effects of increased DER adoption or future adoption do not obligate or require regulators to utilize demand charges, and it seems that, at a minimum, demand charges, if a large portion of a customer's distribution bill, would over-collect customer costs as demand costs.[159] In some respects, these conversations may mirror regulators' straight fixed variable discussions. Regulators may find large or non-coincident peak demand charges operate more like a fixed charge (as the "middle ground" or "compromise" argument from proponents highlights), which should, therefore, be avoided for similar reasons as to why the alleged high percentages of fixed electricity costs stemming from infrastructure are not currently fully recovered in a fixed charge.[160]

Finally, as mentioned before, regulators should be cautious if implementing demand charges to protect a utility's revenue recovery for the distribution grid is the goal, especially if the DER benefits to the grid are not accounted for in any way. In the example of combining demand charges with an NEM rate, the regulator may simply be layering one proxy, or imperfect solution, over another without addressing the underlying threats and opportunities for their distribution system. Implementing large or non-coincident peak demand charges for an entire residential or small commercial rate class to counter perceived cost shifting from a limited set of actors would most likely be a disproportional response if adoption rates are low or under, say, 10 percent.

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159 NARUC, *Electric Utility Cost Allocation Manual.*

160 EEI Primer, 13. *See also* sections on fixed charges and rates theory for more discussion.

STAN FARYNIARZ

Appendix SF-5

Excerpt from the 1988 Edition of Principles of Public Utility Rates

and acceptability. However, the sequence in which the ten attributes are presented is not meant to suggest any order of importance. Moreover, there is, perforce, some inconsistency and redundancy in any such listing. We are simply trying to identify the desirable characteristics of utility performance that regulators should seek to compel through edict.

Revenue-related Attributes:

1. Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality and safety.

2. Revenue stability and predictability, with a minimum of unexpected changes seriously adverse to utility companies.

3. Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers and with a sense of historical continuity. (Compare "The best tax is an old tax.")

Cost-related Attributes:

4. Static efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:

   (a) in the control of the total amounts of service supplied by the company;

   (b) in the control of the relative uses of alternative types of service by ratepayers (on-peak versus off-peak service or higher quality versus lower quality service).

5. Reflection of all of the present and future private and social costs and benefits occasioned by a service's provision (i.e., all internalities and externalities).

6. Fairness of the specific rates in the apportionment of total costs of service among the different ratepayers so as to avoid arbitrariness and capriciousness and to attain equity in three

dimensions: (1) *horizontal* (i.e., equals treated equally); (2) *vertical* (i.e., unequals treated unequally); and (3) *anonymous* (i.e., no ratepayer's demands can be diverted away uneconomically from an incumbent by a potential entrant).

7. Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (i.e., subsidy free with no intercustomer burdens).

8. Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.

Practical-related Attributes:

9. The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.

10. Freedom from controversies as to proper interpretation.

Lists of this nature are useful in reminding the ratemaker of considerations that might otherwise be neglected, and also useful in suggesting important reasons why problems of practical rate design do not yield readily to scientific principles of optimum pricing. But they are unqualified to serve as a base on which to build these principles because of their ambiguities (how, for example, does one define "undue discrimination"?), their overlapping character, their inconsistencies, and their failure to offer any basis for establishing priorities in the event of a conflict. For such a basis, we must start with a simpler and more fundamental classification of ratemaking functions and objectives.

Some of these attributes in the aforementioned list are based directly on the primary functions of public utility rates first presented in Chapter 4, and the related objectives to be sought in the establishment of a cost-based standard of ratemaking (Chapter 5). These objectives provided the basis for development of the criteria of a fair return (Chapter 10). These same objectives, derived from the four primary functions, can now be used to specify the criteria of a sound rate structure discussed in the following section.

The Primary Criteria Are Based on the Objectives of Regulation

General principles of public utility rates and rate differentials are necessarily based on simplified assumptions both as to the objectives

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION
Docket DE 16-576
Development of New Alternative Net Metering Tariffs and/or
Other Regulatory Mechanisms and Tariffs for Customer-Generators
Response to Commission Staff's Data Requests to The Alliance for Solar Choice - Set 1
Request Received: November 4, 2016
Response Date: November 14, 2016

Request No. Staff 1-20
Witness: R. Thomas Beach

REQUEST:
Refer to the Direct Testimony of R. Thomas Beach, p. 18, lines 7-19. Is the value of banked credits different (and if so, more or less) than the value of the exported power which creates those credits in a typical DG customer transaction? Please explain what impact would the elimination of banking have on a DG customer.

RESPONSE:
No. The value of banked credits should be equal to the value of the exported power which creates those credits. The "banking" of credits is simply an accounting mechanism in which a customer does not receive the value of a credit until a subsequent month. A kWh credit is fungible, so it is difficult to trace a May credit directly to August usage. Further, if there is a concern that a lower-cost spring credit could be used to offset higher-cost summer usage, the best solution is to encourage the use of seasonal time-of-use rates and to value NEM credits in dollar terms, as is done in states like California that have a significant penetration of NEM customers on TOU rates. This will more accurately value NEM credits. Thus, it is entirely reasonable for a kWh credit in the current month to offset a kWh purchase in a future month. Also see response to Unitil 1-30.

STAN FARYNIARZ
Appendix SF-7
Excerpt from 2016 NARUC Manual on Distributed Energy Rate Design and Compensation

IV. DER Considerations, Questions, and Challenges

Often, discussions on DER are made more difficult due to the regulatory framework and utility incentives that have been in place for decades—or in some instances a century—being challenged by these new technologies. Traditional means of regulation, rate design, and planning largely assume the utility will meet all demand with large, central-station generation facilities. With the increase in DER and the recent lack of load growth, the current regulatory and utility models are a constraint to effectively address the growth of DER and its impacts on utility and regulatory frameworks. Identifying and understanding these challenges will assist the regulator in determining an appropriate rate design to implement for its utilities.

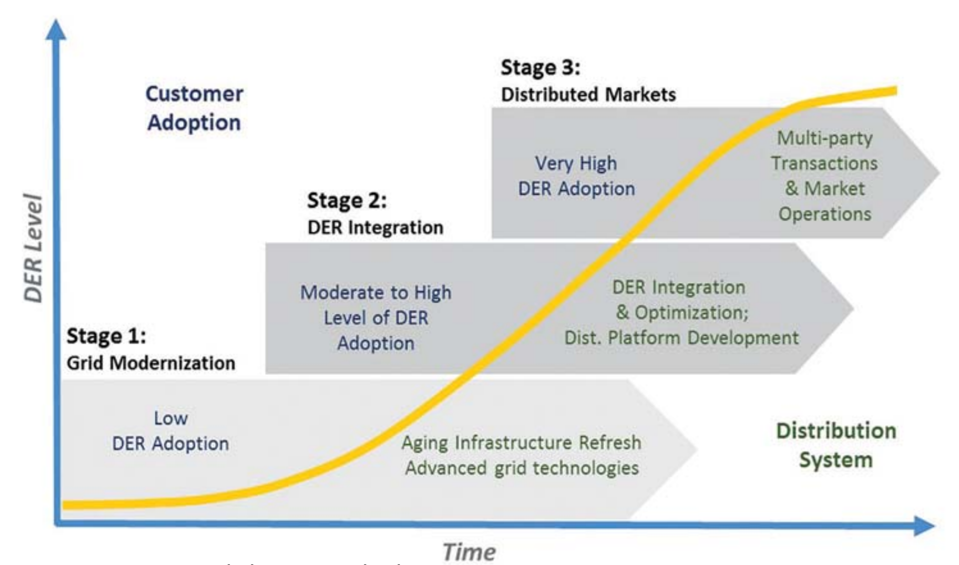
A. Ongoing Monitoring and Adoptions Rates

The level and pace of adoption of DERs in a system is important in the determination of what, if any, policy reforms are needed. The actual adoption levels of DER vary greatly across the country and even within the same jurisdiction. Since all electric systems are affected by DER increases differently, before a jurisdiction embarks on the journey to implement substantive reforms due to the growth of DER adoption, it should look closely at data, analyses, and studies from its particular service area before any such actions are taken. The impacts that are occurring in one jurisdiction due to higher DER adoptions may not necessarily be the same for another that is experiencing similar DER adoption levels.

In a report for LBNL's "Future Electric Utility Regulation" series, Paul DeMartini and Lorenzo Kristov outline a path for regulators and utilities to plan for future utility and regulatory roles.[80] In this paper, they include an adoption curve that points out the importance of monitoring adoption rates of

80 DeMartini and Kristov, *Distribution Systems.*

DER across a jurisdiction. Conceptually, the curve identifies three stages of activity: grid modernization, DER integration, and distributed markets. Each stage is identified with two characteristics: adoption of DER and installation of technology to support DER development. The majority of jurisdictions are still located in stage 1, where there is a low amount of DER adoption and utility investments in grid modernization are still underway. According to DeMartini and Kristov, the move into stage 2 occurs when DER adoption "reaches beyond about 5 percent of distribution grid peak loading system-wide."[81] Stage 3 occurs when a high amount of DER adoption occurs and regulators construct a system to allow for multi-sided transactions to occur between DER and the distribution utility, but also to and from customers. This means the development of policies to enable distribution-level markets, and determining the role of the distribution utility into a market facilitator role.[82] This process is depicted in the figure below.



Source: Lawrence Berkeley National Lab

81 *Id.*, 9.

82 *Id.*, 10.

This discussion is included here to provide regulators with a visual of a future for DER adoption and an awareness that decisions on DER rate design and compensation methodologies are not static determinations that can be made once and then left alone. Rate design and compensation decisions made in one year will likely need to be reviewed, modified, or changed over time as technology continues to develop, as customers adopt DER at greater (or slower) rates, and as needed to support economics. For example, a decision to adopt net energy metering (NEM) as the compensation methodology may be appropriate if a regulator decides to incentivize adoption rates of solar PV; however, as adoption rates increase, it may not be necessary to continue to provide such an incentive. As such, regulators should remain flexible in their decision making. To continue the example, NEM may result in clustering of solar PV, which may cause the utility to incur additional costs to shore up reliability; a regulator may want to consider an alternative compensation methodology to reflect the costs of solar PV at that location. Alternatively, should other technologies, such as storage or EVs, increase in adoption, a regulator may try to turn NEM into a technology-agnostic program, or may choose to implement an entirely new suite of compensation options. All the while, the regulator will need to also address how the compensation methodology is working with the existing rate design for those customers.

It is imperative that a regulator understand the tradeoffs in determining an appropriate compensation methodology, both in terms of technology adoption (does the methodology emphasize one technology over another; what does that mean to the market and the utility?) and over time (does the methodology encourage adoption of specific technologies in the short term as opposed to allowing a variety of technologies to develop over time to meet grid needs?). The availability of new technology can assist regulators in making these decisions. Hawaii, for example, has had significant adoption of solar PV, and the Hawaii Public Utilities Commission decided to close its NEM tariff altogether, deciding that other compensation methodologies and rate designs are more appropriate for its jurisdiction.[83] Understanding and monitoring how DER is affecting the grid and utility rates is essential to fairly compensating DER. A jurisdiction must also be flexible enough to recognize when those methodologies and rate designs are no longer meeting its policy goals. At that time, it is appropriate to consider other means of determining compensation or other rate design options.

For jurisdictions with currently low DER adoption levels and with current policies not designed to spur DER growth, reforms may not be as time sensitive in contrast to the needs of jurisdictions with DER. For the jurisdictions with low DER adoption and growth, there is time to plan and take the appropriate steps and avoid unnecessary policy reforms simply to follow suit with actions other jurisdictions have taken. Reforms that are rushed and not well thought out could set policies and implement rate design mechanisms that have unintended consequences such as potentially discouraging customers from investing in DER or making inefficient investments in DER. That is not to say a jurisdiction should ignore the issue. Understanding how its existing rate design interacts with its compensation may be worthwhile to consider at any time. The important point is that a jurisdiction be situated to analyze, plan, and be prepared for its next steps before the market and customer adoption rates overtake its ability to respond.

To better identify locations for development of DER, a utility needs to understand the characteristics of its grid. Technologies like ADMS and DERMS can facilitate that. The end result of this modeling is a hosting capacity analysis of the distribution grid feeders. Hosting capacity helps the distribution utility assess the impacts of DER on its feeders, and identify available capacity on those feeders.[84] This analysis can determine where there is available capacity and where there is little available capacity; making this information available

83 *Instituting a Proceeding to Investigate Distributed Energy Resource Policies*, Decision and Order No. 33258, Hawaii PUC, Docket No. 2014-192 (October 12, 2015).

84 EPRI, "Hosting Capacity Method," http://dpv.epri.com/hosting_capacity_method.html; EPRI, "Distribution Feeder Hosting Capacity: What Matters When Planning for DER?" (EPRI, Palo Alto, CA, April 2015).