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The Full Cost of Electricity (FCe-)

A Comparison of New Electric Utility Business Models

PART OF A SERIES OF WHITE PAPERS

TEXAS
The University of Texas at Austin

THE FULL COST OF ELECTRICITY is an interdisciplinary initiative of the Energy Institute of the University of Texas to identify and quantify the full-system cost of electric power generation and delivery – from the power plant to the wall socket. The purpose is to inform public policy discourse with comprehensive, rigorous and impartial analysis.

The generation of electric power and the infrastructure that delivers it is in the midst of dramatic and rapid change. Since 2000, declining renewable energy costs, stringent emissions standards, low-priced natural gas (post-2008), competitive electricity markets, and a host of technological innovations promise to forever change the landscape of an industry that has remained static for decades. Heightened awareness of newfound options available to consumers has injected yet another element to the policy debate surrounding these transformative changes, moving it beyond utility boardrooms and legislative hearing rooms to everyday living rooms.

The Full Cost of Electricity (FCe-) study employs a holistic approach to thoroughly examine the key factors affecting the *total direct and indirect costs* of generating and delivering electricity. As an interdisciplinary project, the FCe- synthesizes the expert analysis and different perspectives of faculty across the UT Austin campus, from engineering, economics, law, and policy. In addition to producing authoritative white papers that provide comprehensive assessment and analysis of various electric power system options, the study team developed online calculators that allow policymakers and other stakeholders, including the public, to estimate the cost implications of potential policy actions. A framework of the research initiative, and a list of research participants and project sponsors are also available on the Energy Institute website: energy.utexas.edu

All authors abide by the disclosure policies of the University of Texas at Austin. The University of Texas at Austin is committed to transparency and disclosure of all potential conflicts of interest. All UT investigators involved with this research have filed their required financial disclosure forms with the university. Through this process the university has determined that there are neither conflicts of interest nor the appearance of such conflicts.

This paper is one in a series of Full Cost of Electricity white papers that examine particular aspects of the electricity system.

Other white papers produced through the study can be accessed at the University of Texas Energy Institute website: **energy.utexas.edu**

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Lyndon B. Johnson School of Public Affairs
Policy Research Project Report NUMBER 191

A Comparison of New Electric Utility Business Models

Energy Institute | Lyndon B. Johnson School of Public Affairs

The University of Texas at Austin

LBJ SCHOOL
THE UNIVERSITY OF TEXAS AT AUSTIN

The LBJ School of Public Affairs publishes a wide range of public policy issue titles. ISBN-13: 978-0-89940-819-4 Cover Design by the i2i Group in Austin, Texas.

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

ABBREVIATIONS GUIDE

ADMS	Advanced Distribution Management System
ANSI	American National Standards Institute
ARRA	American Recovery and Reinvestment Act
BNEF	Bloomberg New Energy Finance
BQDM	Brooklyn/Queens Demand Management
BTU	British Thermal Unit
COS	Cost of Service
CPUC	California Public Utilities Commission
CSS	Customer Side Solutions
DCEA	DER Coordination Entity Aggregate
DER	Distributed Energy Resources
DERMS	Distributed Energy Resources Management Systems
DG	Distributed Generation
DNO	Distributed Network Operator
DR	Demand Response
DSIP	Distributed System Implementation Plan
DSM	Demand-Side Management
DSO	Distribution System Operator
DSP	Distributed System Platform
DSPP	Distributed System Platform Provider
EAM	Earnings Adjustment Mechanism
EE	Energy Efficiency
EIA	U.S. Energy Information Administration
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ESM	Earnings Sharing Mechanism
ESU	Energy Services Utility
EV	Electric Vehicle
EVTC	Electric Vehicle Transportation Center
FERC	Federal Energy Regulatory Commission
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GEMA	Gas and Electric Markets Authority
GW	Gigawatt
GWh	Gigawatt hour
HC	Hydrocarbons
HECO	Hawaiian Electric Company
HEV	Hybrid Electric Vehicle
HVAC	Heating, Ventilation, and Air Conditioning
IDSO	Independent Distribution System Operator
IOUs	Investor-Owned Utilities
IRM	Innovation Rollout Mechanism
ISO	Independent System Operator
ITC	Investment Tax Credit
IUS	Integrated Utility Services
kW	Kilowatt
kWh	Kilowatt hour
LBNL	Lawrence Berkeley National Laboratory
LED	Light Emitting Diode
LRAM	Lost Revenue Adjustment Mechanism
MBR	Market Based Revenue
MRP	Multiyear Rate Plan
MW	Megawatt
MWh	Megawatt-hour
MWh	Megawatt hour
NARUC	National Association of Regulatory Utility Commissioners
NEM	Net Energy Metering
NIA	Network Innovation Allowance
NIC	Network Innovation Competition
NM	Net Metering
NREL	National Renewable Energy Lab
NUC	Network Use Charge
NYREV	New York's Reforming the Energy Vision
O&M	Operation and Maintenance
Ofgem	Office of Gas and Electric Markets
PBR	Performance-Based Ratemaking
PEV	Plug-In Electric Vehicle
PIM	Performance Incentive Mechanism
PPSB	Potential Profitability and the Social Benefits of Coordination
PSR	Platform Service Revenues
PTID	Point Identifier
PUC	Public Utility Commission
PURPA	Public Utilities Regulatory Policies Act
PV	Photovoltaic
Quads	Quadrillion British Thermal Units
R&D	Research and Development
RAV	Regulatory Asset Value
REC	Renewable Energy Credit
RFP	Request For Proposal
RIIO	Revenue = Incentives + Innovation + Outputs
RMI	Rocky Mountain Institute
RPS	Renewable Portfolio Standard
RRAR	Revenue Requirements At Risk
RSC	Regulatory Service Charge
RTO	Regional Transmission Operator
SA	Super-Aggregate
SCED	Security Constrained Economic Dispatch
SIM	Smart Integrator Model
SREC	Solar Renewable Energy Credit
SVC	System Value to Customer
T&D	Transmission and Distribution
TE	Transactive Energy
TOU	Time of Use
TPO	Third Party Ownership
USS	Utility Side Solutions
VOS	Value of Solar
VOST	Value of Solar Tariff

FOREWORD

The Lyndon B. Johnson School of Public Affairs emphasizes interdisciplinary research on policy problems in the graduate public affairs program. A major part of this program is the nine-month policy research project, in which faculty members direct the research of a small group of graduate students on a policy issue of concern to a government, private, or nonprofit client. This client relationship brings the students face to face with administrators, legislators, and other officials active in the policy process and demonstrates that research in a policy environment demands special talents. It also illuminates the difficulties of applying research findings in the world of complex problems and political differences.

This report describes a policy research project conducted in the 2016-17 academic year with support from multiple government and non-government organizations involved in Electric Utility governance and regulation at the state and federal level. The Energy Institute at The University of Texas at Austin sponsored the study as part of their larger multi-disciplinary study "The Full Cost of Electricity". The study addresses how the adoption and integration of Distributed Energy Resources onto the Electric Grid is stressing the traditional electric utility business model.

As part of this objective, the project team examined six new business models for the utility. Specifically, it explores New York's Reforming the Energy Vision (NY REV), the California (CA) Proceedings, the United Kingdom's Revenue = Incentives + Innovation + Outputs (UK RIIO), the Lawrence Berkeley National Laboratory (LBNL) model, the Rocky Mountain Institute (RMI) model, and the Transactive Energy (TE) model. It is important to note that the first three of these models are real and operational in the physical world while the other three are theoretical.

The curriculum of the LBJ School is intended not only to develop effective public servants but also to produce research that will inform those already engaged in the policy process. This research project accomplishes both tasks. This report has strived to keep pace with changes made to the NY REV and California Proceedings during the nine-month course as well as the constant feedback cycle between the experiences of the operational models in the real world and the subsequent modifications to the theoretical ones. In other words, the students were thrown into the "sausage factory" of Policy Development and Policy Implementation. Hopefully, they haven't been scared off.

Angela Evans, *Dean*

ACKNOWLEDGMENTS AND DISCLAIMER

Publishing a Policy Research Project (PRP) Report isn't just a class assignment — it is also a test of endurance and persistence. Our students and we benefited greatly from many individuals, agencies, and organizations and we would like to thank all of them for their guidance which enabled the completion of this report.

We would like to give particular thanks to the guest speakers who gave the class invaluable insight into the workings of the electric utility industry and the business models being investigated: (in order of appearance)

- **Mark Dreyfus** – Vice-President, Regulatory Affairs and Corporate Communication, Austin Energy
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- **Jim Lazar** – Regulatory Assistance Project
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- **Jon Wellinghoff** – Chief Policy Officer, Solar City

Additionally, we want to acknowledge the help and sponsorship of the Energy Institute, and particularly, **Dave Tuttle**, for his assistance in the class and **Ben Griffiths** for his research on fuel subsidies and incentives.

We also want to thank and acknowledge all the staff and faculty at the LBJ School of Public Affairs that made this Policy Research Project possible and helped us in many ways in the conduct of the class.

Finally, it should be noted that neither the LBJ School of Public Affairs nor The University of Texas at Austin nor the persons interviewed for this project necessarily endorse the views or findings of this report.

EXECUTIVE SUMMARY

The electricity sector in the United States is experiencing a period of significant transition. Since its inception in the late nineteenth century, the electric utility has produced electricity in power plants and supplied it to the public through the electric grid at a rate based largely on the consumer's usage. In recent years, however, Distributed Energy Resources (DER) have disrupted this model. DER adoption is ushering in an electricity system that is more dynamic, decentralized, and energy efficient. While this paradigm shift has inherent benefits for ratepayers and society at large, it threatens the traditional utility business model.

The utility will need to consider alternative business models to remain viable and realize the potential benefits of DER. To facilitate the process, this report provides an analysis of six new business models for the utility. Specifically, it explores the California (CA) Proceedings, the Lawrence Berkeley National Laboratory (LBNL) model, New York's Reforming the Energy Vision (NY REV), the Rocky Mountain Institute (RMI) model, United Kingdom's Revenue = Incentives + Innovation + Outputs (UK RIIO), and the Transactive Energy (TE) model. Our analysis identified three common themes across the six models:

- **Rate Structure Reform:** These models recognize the traditional cost of service (COS) rate structure is insufficient as the sole means of recovering fixed costs and creating adequate revenue to offset the revenue loss from DER. The models adopt a Performance-Based Ratemaking (PBR) structure that shifts the utility's focus from COS to revenues awarded for improving performance.
- **Implementation of DER:** These models prioritize integrating renewables onto the grid. The models seek to incorporate both utility-scale and distributed generation onto the electric system without penalty to the utility or ratepayers.
- **Customer Engagement:** The traditional relationship between the utility and ratepayers is replaced by one which gives the consumer greater control over their energy bill. The customer can choose energy efficiency programs that fit their needs, negotiate energy usage with the utility, and generate their own electricity through DER.

Each new business model has its own mix of incentives and revenue structures with differing consequences for stakeholders. The following chart highlights these variations.

Comparative Analysis of New Business Models

Evaluation metric	Business Model					
	NY REV	CA	RIIO	LBNL	RMI	TE
COS to PBR Transition	●	◑	●	●	●	◑
DER Encouragment	●	◑	●	●	●	●
DER as Cost Reduction Tool	◑	◑	○	◑	◑	○
Customer Engagement	●	◑	●	●	○	◑
Platform Model	●	◑	○	●	◑	●
Fixed Cost Recovery	COS + Fixed Change	COS + Min. Bill	Policy + RAV	N/A	NUC + Tariff	COS + Access Fees
Profit-Making	PER+MBR	PER+MBR	PBR	MBR	PER+MBR	MBR
Role of DSO	None	Operation	Price Settings + Regs	Operation	Operation	Operation
ESU or SIM	SIM	SIM	SIM	Both	Both	SIM

● YES ◑ SOMEWHAT ○ NO

COMPARISON OF NEW BUSINESS MODELS

These models are generally unsustainable in the scenario of low electric load growth and high DER penetration. The utility's revenue declines when demand for electricity drops, and DER drives falling demand. However, the utility's costs remain unchanged, or even increase as DER becomes more widespread. If the current trend of increased DER penetration and decreased load growth continues, these models will experience the same profitability issues facing the utility today.

While all these models cease being viable under certain conditions, they provide an important step forward for the utility. There is no one-size-fits-all solution to shifts in electric demand, generation, and efficiency. However, utilities can better anticipate and respond to these trends by keeping in mind the following:

- These models will struggle in a low load growth, high DER scenario.
- The need to accommodate uneven fiscal impacts by understanding utility and market characteristics.
- The platform business model has only limited applicability to the utility industry.
- These models work best as transitional models.
- Some utilities might not survive the transition (in their current form) to high penetration of DER.
- These models will benefit participating customers and society at large.
- None of these models propose a complete move away from traditional cost of service regulation.
- A fully regulated model might be the best option for distribution utilities.
- The IDSO might be the preferable operator system. Such an operator might be a non-profit or government entity.
- The need to accommodate uneven physical impacts by using software to understand structural characteristics.
- Once a saturation point is reached, additional DER will have limited value to the overall system.
- Physical limitations of peer-to-peer transactions will ultimately hinder growth in distribution system markets, and fiscal limitations will affect distribution systems.

BACKGROUND: AN ELECTRICITY SYSTEM IN TRANSITION

The goal of the report is to provide stakeholders with insight as they navigate changes in the electric power sector. The opening section provides background related to the utility's challenges. The following section includes an overview of new business models that have been proposed or recently implemented, as well as a comparative analysis that evaluates the differences between the models. Finally, the report presents major conclusions drawn from the analysis. The results of this report are intended to inform the energy industry at large as conversations on how to adapt to a more dynamic, decentralized, and energy efficient electric system continue.

The electric utility was originally designed to provide universal access to electricity, while simultaneously creating investor profits. Thomas Edison's secretary, Samuel Insull, devised the "Cost of Service" (COS) business model in the late nineteenth century, and it has scarcely changed since then. However, the model might now be approaching the end of its usefulness. A series of modern challenges – including declining electric load growth, improvements in energy efficiency, and the rise of distributed generation (DG) – have placed new stresses on the utility and its capacity to turn a profit using COS.

Alternative business models have emerged to counteract such market disruptions. These models address the issues facing the utility with different approaches to subsidizing and integrating Distributed Energy Resources (DER) installations, recovering fixed costs, and modernizing the role of the utility. However, in a scenario with low load growth and high DER penetration, the financial viability of these models falters. Moreover, if the models' proposed revenue-earning activities fail to generate sufficient profits, they revert to the classic COS model they were intended to replace.

THE TRADITIONAL BUSINESS MODEL

The utility's commercial operations have long been supported by a regulatory paradigm that permits the recovery of fixed costs and a fair rate of return on investments. In the 1970s, the deregulation movement gave way to a more diverse set of utility structures. Ratemaking, on the other hand, remained unchanged, as the utility continued to set prices according to the cost of service (COS) model.

Structure of Utilities

There are a variety of utility structures in the U.S. Because of deregulation (initiated by the Public Utilities Regulatory Policy Act (PURPA) of 1978[1]), states generally have freedom to choose the most climate and fuel source-appropriate mechanisms to maximize delivery electricity while also fairly compensating electricity suppliers. The Federal Energy Regulatory Commission (FERC) oversaw and implemented deregulation policy in the 1980s, and under their continued regulatory oversight nearly half of all states are deregulated in some form today.[2]

Knowledge of Texas' utility regulation is a useful tool for understanding deregulation policy throughout the nation. In 2002, Texas' Senate Bill 5 unbundled ("deregulated") generation, distribution, and retail. Private firms build generation facilities (coal, natural gas, wind, etc.) and sell generated electricity at a market rate to retailers. Public utilities were given the choice to retain their status as vertically integrated utilities or to opt into the de-regulated market. The Electric Reliability Council of Texas (ERCOT), the state's independent system operator, operates wholesale energy markets while also planning

1 Rebecca McNerny, "What's Changing and Why".

2 Frontline PBS, "What's FERC?".

for and operating the transmission grid.[3] ERCOT acts as a middleman for the transaction between generation companies and retailers. Texas therefore contains three types of utility systems: Municipal, Cooperative, and Investor Owned.

Municipal utilities and co-ops conduct their own generation, maintain transmission and distribution, and sell electricity to the customer. Excess revenues are returned to the citizens via clawback initiatives and are either invested in non-utility public initiatives or rebated to future bills. Publicly owned electric utilities serve an important social welfare function; a portion of each bill goes to non-electricity related initiatives.

Investor-owned utilities are the most common form of distribution in Texas. Overseen by the Public Utility Commission, "Power to Choose" is the statewide clearinghouse for all retail utility actions. Customers buy electricity from a database of providers, all of whom offer different rates and rate-structures. In general, citizens of large cities utilizing the retail sale system, such as Houston and Dallas, pay higher bills than cities that maintained vertically integrated municipal utilities.[4]

Cost of Service Ratemaking

James Bonbright's seven principles of rate design are the fundamental criteria through which utility managers and policymakers frame arguments and business outlooks. Referred to as "Criteria of a Sound Rate Structure" in his original ratemaking manifesto, they are now colloquially referred to as "Bonbright's Principles of Rate Design." His tenets are:

1. All rates should be understandable to the general public.
2. Uncontroversial rates are easily applied and maintained, and might be utilized at large without pushback from consumers.
3. Rates must effectively compensate sellers such that they are incentivized to continue production.
4. Stable rates and revenues provide predictability, making it easier for both customers and the utility to realistically budget their expenses and revenues.
5. Rates should be set fairly, respective to levels of use and distance from a power source.
6. Rates should not discriminate against people or groups for any reason.
7. Rates should promote efficiency and discourage waste.[5]

Cost of service (COS) ratemaking generally follows these principles; it is easy to understand, not controversial, incentivizes sellers, and is fair and non-discriminatory. However, COS is becoming less predictable, and it does not promote efficiency. This section will provide an overview of the cost of service model.

Investor-owned utilities collect revenues from customers as allowed by their public utility commissions. The cost of service model is often referred to as the traditional model in the U.S. In this model, regulators allow the utility to recover rates that match their costs of providing services plus a rate of return, incentivizing investors to take on the risk of investing in capital. The amount of revenue the utility requires to provide services is referred to as the revenue requirement. The most general form of the revenue requirement is:

Revenue Requirement = Operating Costs + Depreciation Costs + Taxes + (Rate Base x Rate of Return)

- Operating Costs: Short-term capital costs, maintenance costs, and labor
- Depreciation Costs: The reduction in the value of fixed assets
- Rate Base: Mostly includes depreciation-adjusted long term capital investments. Determining what goes into the rate base significantly affects how the utility makes investment decisions.

3 ERCOT's non coverage area is very small, limited to the far east and west that are covered by Southwest Power Pool (SPP) and Western Interconnect (WECC) respectively.

4 Jonathan Fahey, "America's Highest Power Bills", Published January 4, 2010.

5 James Bonbright, Albert L. Danielsen, and David R. Kamerschen, *Principles of Public Utility Rates* (1961), Pg. 291.

- Rate of Return: The rate allowed by the regulator on capital investment, including return on equity and return on debt weighted proportionally based on how much of each type of security was provided as capital.

In most cases, the revenue requirement is determined based on a test year, then revisited during a rate case. Rate cases usually occur at the request of a utility when they invest in capital, so their rate base might be adjusted to match their capital expenditures. The underlying problem for the cost of service model becomes evident in a future with prevalent Distributed Energy Resources (DER). The cost of service model provides financial incentive for the utility to invest in capital and increase sales. DER reduces load, reducing electricity sales and reducing opportunities for utilities to grow their rate base.

Whether the regulator allows an increase in the rate base depends on extensive prudence reviews to the utility's capital costs. The purpose of these prudence reviews is to make sure the utility does not over-invest since they have financial and material incentive to do so. In theory, after the utility has invested, the regulator can apply a cost disallowance based on mismanagement of costs; however, practice shows that this disallowance rarely occurs.[6] Between rate cases, cost trackers and rate riders are applied to treat changes in costs that are out of the utility's control and would be considered prudent by the regulator, such as fuel costs.

The revenue requirement is then used to determine customer rates based on the amount of electricity sales expected. If the actual amount of electricity sales varies from what was projected and the utility does not change customer rates, the utility will receive a total revenue that is higher or lower than the revenue requirement. For instance, if a utility sold less MWh than it had expected due to an unforeseen switch to rooftop solar by some residents, its total revenues at the end of the year would be less than the revenue requirement. Consequently, said utility might request a rate case to address its revenue attrition by increasing customer rates. However, this rate increase might make rooftop solar more financially attractive to customers, further decreasing sales and necessitating additional rate increases. This cycle is known as the "utility death spiral."[7]

FIXED COST RECOVERY

Utility expenses can generally be categorized as either fixed or variable costs. Variable costs are costs that increase or decrease volumetrically with the amount of electricity sold, such as fuel costs. Fixed costs are costs that do not change, regardless of the quantity of electricity sold, though "fixed" costs might become variable when evaluated over long periods of time. Fixed costs include large capital projects, maintaining transmission and distribution systems, labor, providing excess system capacity to meet peak demand, etc.

While retail electricity bills vary across the U.S., most bills include a fixed customer charge and a volumetric charge. The customer charge is typically less than the utility's actual fixed costs, and the volumetric charge partially used to make up the difference. Volumetric charges are often in inclining blocks, meaning higher users pay more per kWh. Two notable benefits to inclining block rates include 1) encouraging conservation through price signals and 2) reducing the burden on low income customers who typically use less electricity.

There are many potential solutions to allow the utility to cover fixed costs. Some of the commonly used methods include:

- **Higher fixed charges:** Higher fixed charges are generally supported by the utility as a means of recovering fixed costs directly. However, opponents of higher fixed charges see the increase in fixed charges as a financial burden on low-income and low usage customers and as a disincentive to conserve energy.

- **Minimum bills:** While minimum bills guarantee the utility will receive some revenue from each customer, they tend to be either too low to fully recover fixed costs or too high to incentivize conservation.

6 Melissa Whited, Tim Woolf, and Alice Napoleon, *Utility Performance Incentive Mechanisms: A Handbook for Regulators* (2015), Pg. 11.

7 See page 21 for a complete description of the "Utility Death Spiral".

- **Demand charges:** Demand charges are an excellent way of recovering Transmission and Distribution (T&D) system costs and costs associated with being able to meet peak demand. Demand charges are already in place for many commercial and industrial customers, but they might be difficult to implement for residential customers who are less able to respond to the charges.

- **Time-varying rates:** Although time-varying rates are generally favored and help address fixed costs associated with meeting peak demand, they primarily address variable costs (such as changes in the cost to generate electricity).

- **Tiered charges:** Tiered (block) rates are already common practice in volumetric charges, but tiered rates might be applicable to fixed customer charges as well to minimize effects on low-income/low usage customers.

- **Revenue decoupling:** Revenue decoupling reduces stress on the utility, but it might insulate them "too well." While decoupling eliminates the throughput incentive (where the utility benefits from selling more electricity), it does not have any other clear customer benefits.

- **Formula rate plans:** Formula rate plans are not as resource-intensive as frequent rate cases, but they might discourage utility efficiency.

- **Lost revenue adjustment mechanisms (LRAMs):** LRAMs are rate adjustments made specifically to adjust for revenue lost due to successfully implemented energy efficiency programs. While LRAMs are seen as less extreme than decoupling, the amount of revenue lost due to one specific program is often prohibitively difficult to calculate precisely.

- **Fees:** Possible fees include transaction fees, connection fees, and fees for specific services. Though beneficial, these fees likely will not be sufficient as the sole method of recovering fixed costs.

Some generally agreed upon priorities for utility bills are transparency, simplicity, ability to incentivize conservation/send meaningful price signals, and the ability for the utility to recover their fixed and variable costs. The utility is accountable to a variety of stakeholders whose priorities don't always agree.

Overall, time-varying rates are generally seen as an important aspect of utility bills, though the utility authors did note that time-varying rates do not address fixed costs directly. Although demand charges are effective for commercial and industrial customers, residential customers might not have the ability to respond to demand charge price signals, and demand charges will require advanced metering. Higher fixed charges might also be effective, especially if programs are implemented to ease the burden on low income customers or if higher fixed charges are paired with other strategies.

Utilities have taken a range of approaches to recovering fixed costs. Hawaiian Electric Company (HECO), faced with extremely high levels of distributed solar, ended its net metering program for new customers and has implemented minimum bills to recover fixed costs.[8] Consolidated Edison (Con Ed), the major electric utility for New York City, breaks down its residential bills into a number of categories, including supply charges (volumetric supply charge, merchant function charge, and taxes), delivery charges (basic service charge and volumetric delivery charge, volumetric system benefit charge, taxes and state surcharges), and sales tax, with quick descriptions of each one on the monthly bill to explain the charges to customers.[9] Con Ed's combination of fixed and volumetric charges provides incentive for customers to conserve electricity while ensuring recovery of fixed costs. Austin Energy uses a value of solar tariff (VOST) rather than net metering to credit customers for solar generation, providing customers the full value of solar and allowing Austin Energy to recover fixed costs by billing based on total household usage instead of net usage.[10]

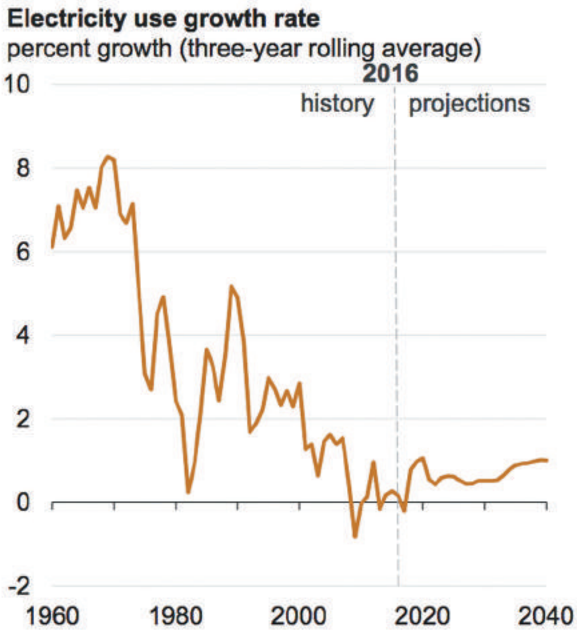
8 Julia Pyper, "Hawaii Regulators Shut Down HECO's Net Metering Program", Published October 14, 2015.

9 Consolidated Edison Company of New York, "Sample Bill – Residential or Small Business".

10 Danielle Murray, "From NEM to Value of Solar", September 29, 2016.

FIGURE 1:

Demand Growth 1960-2040



Source: U.S. Energy Information Administration, *Annual Energy Outlook* (2017). Pg.75.

There are a multitude of approaches available to recover fixed costs. As penetration of DER increases and electricity usage decreases, it is especially important that fixed costs are recovered independently of volumetric rates. Increasing fixed charges (with assistance for low income customers or with tiers), time-of-use pricing, and implementing demand charges for commercial and industrial customers are generally favored approaches to fixed cost recovery by a variety of stakeholders. While tiered rates do not address fixed cost recovery, inclining block rates are generally preferred for volumetric rate design to incentivize conservation and assist low income customers.

MODERN MARKET DISRUPTORS

The electricity sector in the U.S. is in transition. Since its inception in the late nineteenth century, the utility has produced electricity in power plants and supplied it to the public through the grid at a rate based largely on the consumer's usage. In recent years, however, Distributed Energy Resources (DER) have disrupted this model. DER adoption is ushering in an electricity system that is more dynamic, decentralized, and energy efficient. While this paradigm shift has inherent benefits for ratepayers and society at large, it threatens the traditional utility business model.

Electric Load Growth in Decline

The growth rate of electricity demand in the U.S. has been in decline since the 1950s, dropping to its lowest point in 2010 when growth became negative.[11] ***Figure 1*** shows demand growth and projected growth from 1960 to 2040.

While the overall trend is downward, there is significant geographical variability in load growth across the country. ***Figure 2*** shows the percent change in retail electricity sales from 2008 to 2013. This Figure illustrates how some regions, such as the Rust Belt and Appalachia, have experienced sharp declines in load growth.

The Rise of Distributed Energy Resources

Energy efficiency measures, storage options, and end-user owned generation have become more widespread. These, and other technologies that can be deployed at the distribution level to provide value to the grid, are referred to as Distributed Energy Resources (DER). Defined broadly, DER are "demand-side and supply-side resources that can be deployed throughout an electricity distribution system to meet the energy and reliability needs of the customers served by that system. DERs can be installed on either the customer side or the utility side of the meter."[12] Therefore, DER can come in the form of energy efficiency, distributed generation, managed loads, energy storage, and other technologies that can provide ancillary services.[13]

Energy Efficiency

One of the main contributors to declining load growth is increased technological efficiency and higher energy efficiency standards. Energy Efficiency (EE) includes any technology that requires less energy to provide the same service. "In recent history, the growth in electricity demand

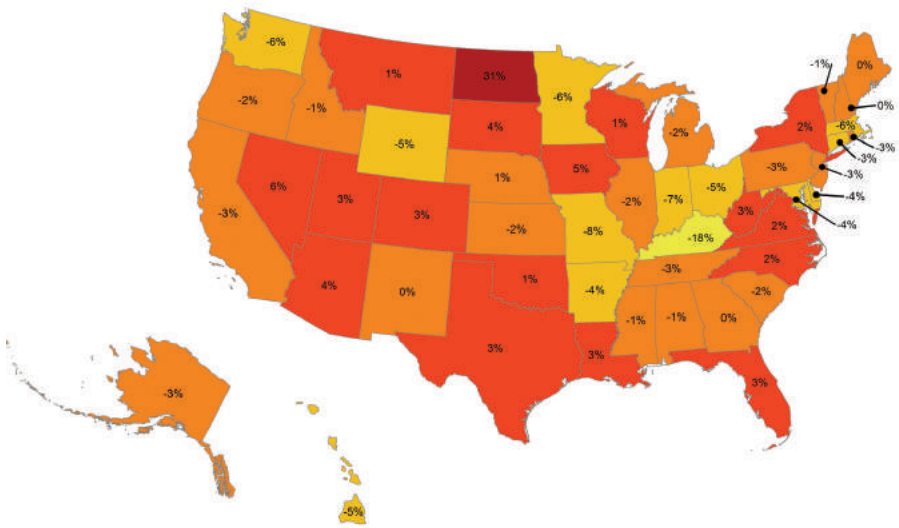
11 Department of Energy, *Quadrennial Energy Review: Energy Transmission, Storage, and Distribution Infrastructure: Appendix C* (2015), Pg. 8.

12 Cheryl Harrington, David Moskovitz, and John W. Rowe, *Profits and Progress Through Distributed Resources* (2000), Pg. 5.

13 Virginia Lacy, Ryan Matley, and James Newcomb, *Net Energy Metering, Zero Net Energy and the Distributed Energy Resource Future* (2012), Pg. 9.

FIGURE 2:

Percent Change in Retail Electricity Sales (kilowatt-hours), 2011– 2016



Source: *Quadrennial Energy Review,* Pg. 9.

has slowed as older equipment was replaced with newer, more efficient stock, as efficiency standards were implemented and technology change occurred, particularly in lighting and other appliances."[14] ***Figure 3*** shows these changes in efficiency of various sectors and technologies since 1980. Increases in efficiency reduces the amount of electricity sold by the utility, shrinking utility revenues.

Distributed Generation

Distributed Generation (DG) is any technology that generates electricity at or near where it is consumed. The Environmental Protection Agency (EPA) divides DG into 4 categories: solar photovoltaic (PV) systems, distributed wind, diesel- or gasoline-powered backup generators, and natural gas fuel cells.[15] Backup generators and natural gas fuel cells are traditional fuel types, and therefore do not exhibit any of the intermittence issues intrinsic in wind and PV systems. Consequently, the primary impact with respect to grid reliability and utility profitability is attributed to distributed, or "behind-the-meter" wind and PV systems.

14 *Annual Energy Outlook* (2017), Pg. 76.

15 U.S. Environmental Protection Agency, *Distributed Generation of Electricity and its Environmental Impacts.*

Distributed wind is still an up-and-coming energy source. A recent report by the National Renewable Energy Laboratory (NREL) indicates its incredible potential in the coming decades, as costs are expected to decrease between 35% - 80% over the next 30 years.[16] However, distributed wind is still relatively uncommon, with a total of 934 megawatts (MW) installed in the US from 2003 to 2015.[17] While distributed wind might expand in the coming decades, PV systems currently account for the vast majority of DG.

There have been expansive increases in the level of installed solar capacity since 1980 due to improvements in technology, reductions in costs, increasingly holistic utility rates, state renewable portfolio standards, federal investment tax credits (ITC) along with state net metering (NM) policies, and utility rebates. In the past five years alone, there have been more PV installations than in the prior 30 years combined, accounting for 35% of all new electricity generation capacity in 2015.[18] ***Figure 4*** shows the installed PV capacity in the U.S. by

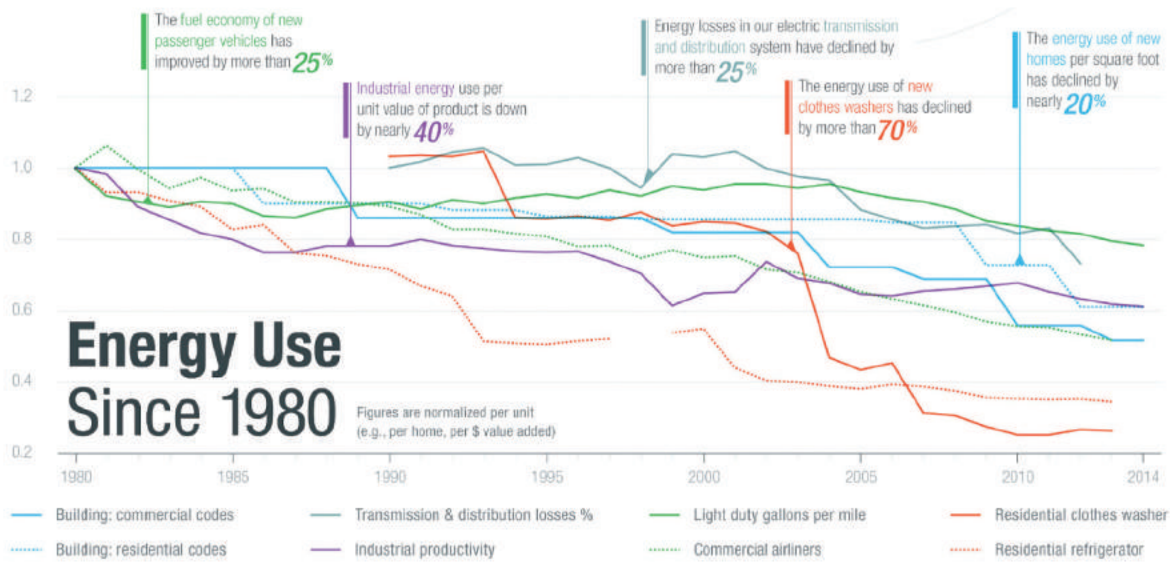
16 Mike Taylor et al, *Value of Solar: Program Design and Implementation Considerations* (2015).

17 Lanz et al, *Assessing the Future of Distributed Wind: Opportunities for Behind-the-Meter Projects* (2016), Pg. v.

18 Solar Energy Industries Association, "U.S. Solar Market Sets New Record, Installing 7.3 GW of Solar PV in 2015", Published February 22, 2015.

FIGURE 3:

Changes in Energy Use for Various Entities, 1980-2014



Source: Steven Nadel, Neal Elliott, and Therese Langer, *Energy Efficiency in the United States: 35 Years and Counting* (2015), Pg. v.

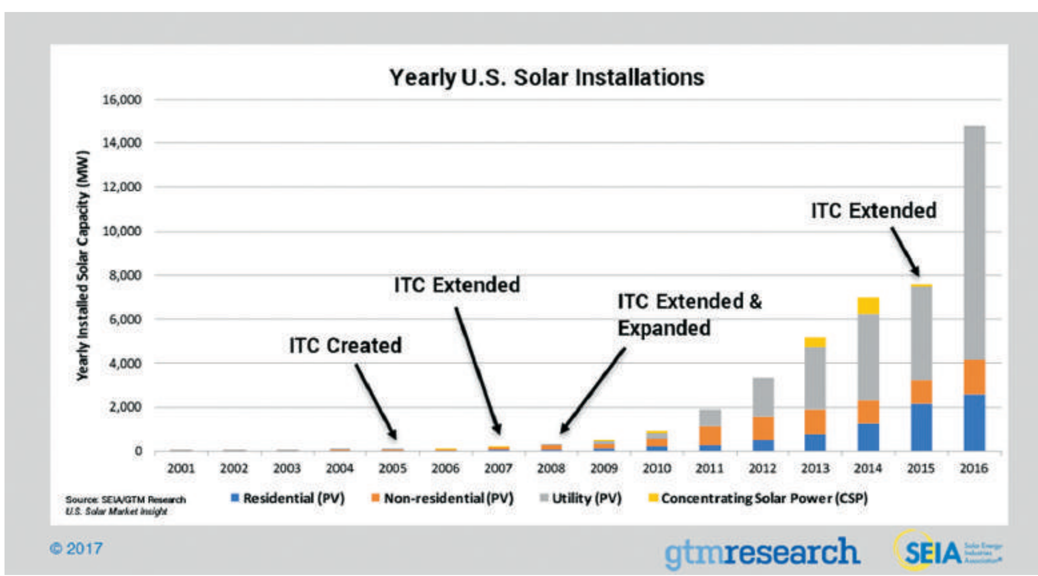
customer class from 2000 to 2016.

The cost of solar PV systems has decreased dramatically in recent years, contributing to the proliferation of PV. Lazard's cost analysis estimates a cost of $2 to $2.8 USD per watt for residential system installations in 2016.[19] ***Figure 5*** shows the amount of end-user PV systems has increased as prices have fallen. As the cost for residential customers fall to $1.00 USD per watt in 2020, high

19 Jim Lazard, *Lazard's Levelized Cost of Energy Analysis Version 10.0* (2016), Pg. 18.

FIGURE 4:

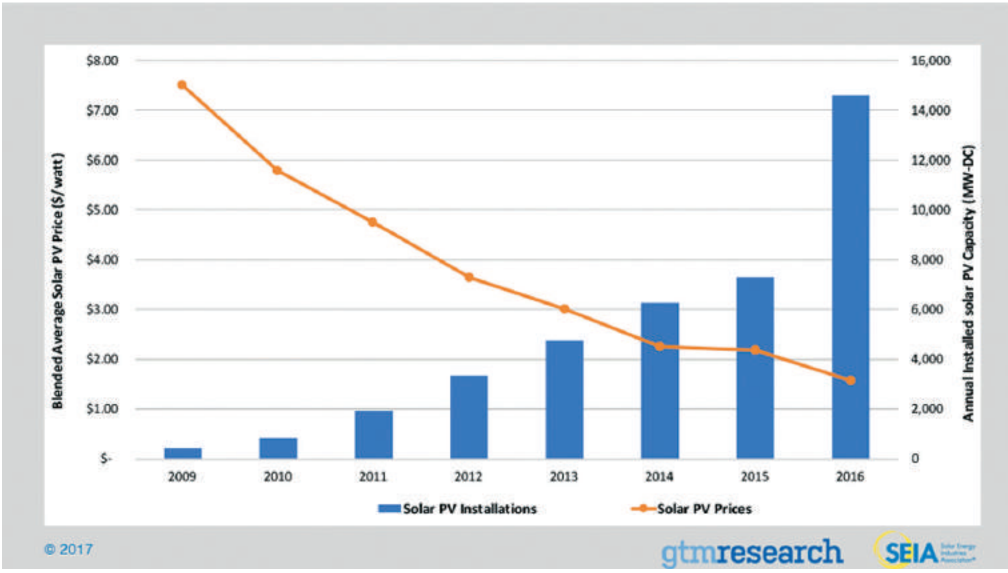
Annual US Solar Installations by Customer Class, 2000-2016



Source: Solar Energy Industries Association, *Solar Industry Data* (2017).

FIGURE 5:

Price Per Watt and Number of Installations of Solar PV, 2009-2016



Source: Solar Energy Industries Association, *Solar Industry Data* (2017).

rates of PV adoption are slated to continue. ***Figure 6*** indicates that residential installations of PV are estimated to grow steadily from 2017 to 2022.[20]

Another driver of increased PV is third-party financing. "No money down" options have reduced the out-of-pocket cost of solar PV. Last year, third-party owned (TPO) units accounted for roughly 72% of new residential solar PV installations.[21]

Although DG penetration nationwide is less than 1%, it is significantly higher in states such as Hawaii, California and New Jersey; overall penetration is increasing at approximately 40% per year.[22] While a single rooftop PV installation might only have a marginal impact on a circuit, multiple rooftop systems on a single circuit could accelerate wear and tear on system components. Additional DER leads to faster replacement and higher system costs for the utility. Most utilities do not consider locational preference of DER, but incorporating location preferences can save significant long-term expenses.[23]

Demand Response

Demand Response generally refers to the ability to lower demand in response to a signal or request from the utility to reduce peak load, usually with some form of financial incentive. While an individual residential customer's demand response is only minimally useful, when aggregated, residential customers can have a significant impact on load.

Energy Storage

Energy storage includes technology such as batteries or any mechanism that stores electricity as another form of energy that can be released as needed. Energy can be stored using chemical, potential, or kinetic energy, or across a concentration gradient. Although not often thought of as a battery, Electric Vehicles (EVs) are one form of storage that is rapidly gaining popularity. EVs

20 Solar Energy Industries Association, *Solar Industry Data* (2017).

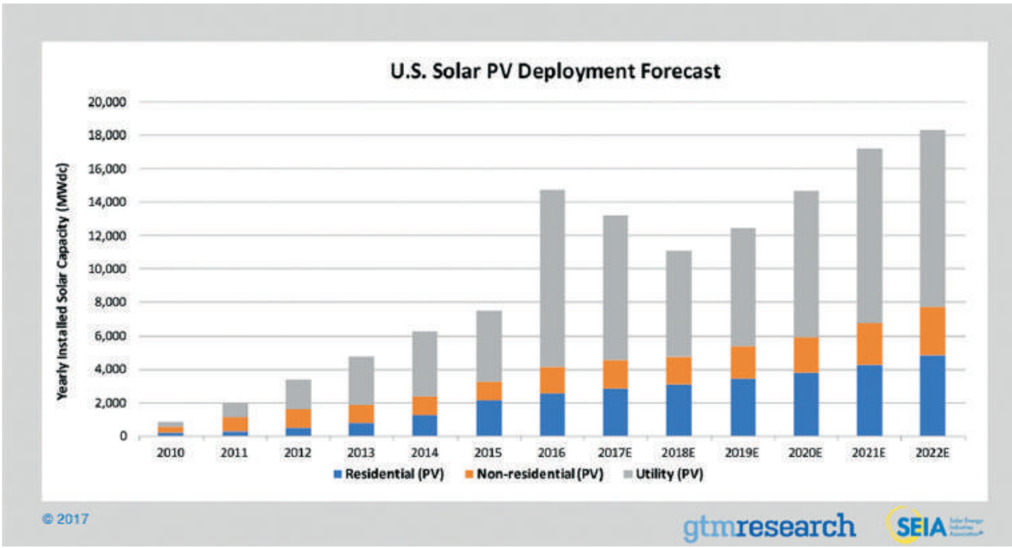
21 Mike Munsell, "72% of US Residential Solar Installed in 2014 Was Third-Party Owned", July 29, 2015.

22 Rich Seguin et al, *High-Penetration PV Handbook for Distribution Engineers* (2016), Pg. 40.

23 Susan F. Tierney, *The Value of "DER" to "D": The Role of Distributed Energy Resources in Supporting Local Electric Distribution System Reliability* (2016), Pg.14.

FIGURE 6:

Forecasted Growth of Solar PV by Customer Class, 2010-2022



Source: SEIA, 2017. Ibid.

of the future might be used to supplement the grid by discharging electricity onto the grid during peak demands, or even to power an individual's house when blackouts cause loss of service. Storage options are also well suited to provide ancillary services benefits.

Effects of Distributed Energy Resources on the Grid

Different types of DER affect the grid in different ways. DER can provide benefits such as voltage support, reduction in transmission losses, and peak demand reduction.[24] However, operational challenges arise from large deployment of DER. Most DER is on the customer-side of the meter and is not owned or operated by the utility. This complicates how the utility plans for and manages generation to meet demand. The utility also lacks visibility since it might not know the exact location or capacity of the devices, and there is usually no system in place to sense and communicate with these resources. DER presents system operators with additional challenges, such as electricity demand becoming less predictable.

Current grid planning processes were not designed to meet the needs of a decentralized electric system. However, if they were adapted to prioritize the integration of DER, the utility could realize a range of benefits, including:

- Peak shaving or peak shifting through controllable demand and energy storage
- Load reduction in congested transmission lines
- Increased reliability through backup power systems

As the penetration of DER increases, physical impacts like overvoltage and thermal overloading start to appear, jeopardizing reliability. Though distribution grids have control and protection mechanisms, they were installed under the paradigm of electricity going from utility-scale generation to load. Large deployment of DER without proper protection mechanisms increases the grid's vulnerability to failure.

24 Electric Power Research Institute, *Distribution Feeder Hosting Capacity: What Matters When Planning For DER?* (2015), Pg. 3.

TABLE 1:

Major DER Characteristics that Impact Operations and Planning

Characteristic	Potential Impacts
Point of interconnection impacts	• Medium-voltage/low-voltage location drives potential benefits that include delivery system upgrade deferral, congestion relief, and delivery system loss reductions. • Location also drives potential challenges, including protection and voltage regulation concerns and operational reliability risks resulting from competing T&D project needs (for example, ride-through).
Visibility and controllability	• Lack of T&D system operator visibility of customer-owned resources adds uncertainty to the load served from the system. • Lack of controllability impairs operator ability to manage power flows, maintain supply-and-demand balance, and uphold reliability standards.
Inverter interface	• Requires system protection and control schemes that differ from traditional synchronous machine-interfaced resources. • Active and reactive power control schemes can support voltage and frequency performance beneficially and more efficiently than those provided by synchronous machines.
Output variability and uncertainty	• Voltage regulation and frequency issues. • Greater need for flexibility in other resources. • Additional operating and planning reserves to ensure that sufficient energy is available to serve load.
Environmental compatibility and fuel costs	• Low or no fuel costs for certain technologies; high for others. • Low or no emissions for certain technologies; high for others.

Source: K. Forsten, The Integrated Grid: A Benefit-Cost Framework (2015), Pg. 4-5.

The variety of impacts that DER can have on an electric system are listed in ***Table 1*** ahead.

Feeder characteristics that determine how DER impact the grid are listed in ***Table 2***.

The size and location of DER is one of the greatest determinants of DER's effect on the grid. Large DER penetration further from the substation is more likely to have a negative impact on system voltage.[25] The voltage level is also an important factor regarding the impact of DER. The higher the voltage, the more resilient it is to higher DER penetration.

Improving the distribution system's infrastructure will ease the transition to higher penetration of DER considerably. Changes in existing distribution system infrastructure that might be needed include replacing relays and breakers, load tap changers, and voltage upgrades at low voltage feeders. Additionally, smart inverters might help increase system stability for high levels of PV penetration, though the cost incurred will depend on whether the inverter is customer or utility owned. Energy storage can be deployed to mitigate some of the adverse impacts of distributed generation, and this system change could result in savings. Many of the impacts to the bulk power are a result of changes to the distribution system. Potential benefits to the bulk power system can only be realized if communication is improved between the bulk and distribution systems.

Determining the threshold level at which DER penetration starts compromising the performance of the distribution system depends on several factors. This threshold will depend on the distribution feeder characteristics (e.g. topology), DER characteristics (e.g. type, size), DER location along the distribution feeder, operating criteria and control mechanisms, and even proximity to other

25 Ibid, Pg. 4-12.

TABLE 2:

Key Feeder Characteristics that Determine How DER Impact the Grid

Feeder topology	Radial vs. networked
Voltage class	Size and location of DER
Regulation equipment	Electrical proximity to other DER
Short-circuit strength and X/R ratio	DER response characteristics
Operating criteria	DER control

Source: EPRI, 2015. Ibid, Pg. 5-3.

DER systems.[26] Therefore, the effect DER has on the system can vary greatly.

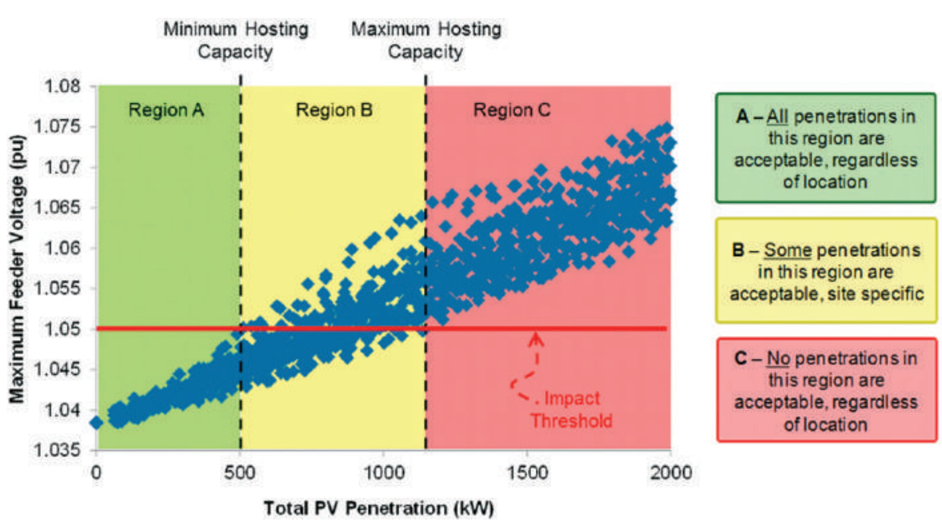
Hosting capacity is defined by the Electric Power Research Institute (EPRI) as "the amount of PV that can be accommodated without impacting power quality or reliability under existing control and infrastructure configurations."[27] In their report, a series of PV deployment scenarios with varying size and location were simulated in a feeder to find the maximum primary feeder voltage. For the same level of PV penetration, some scenarios trespass the American National Standards Institute (ANSI) 105% voltage threshold and some do not. Hosting capacity is unique for every circuit, load profile, and DER scenario. Consequently, one rooftop solar array in a given feeder can add value with no reliability or protection issues, while a comparable array in a different location in the same feeder can cause overvoltage and reliability issues. In ***Figure 7***, all points below the horizontal red line represent different deployment scenarios of DER that can be hosted by the feeder without causing an overvoltage.

26 Ibid, Pg. 2.

27 Ibid.

FIGURE 7:

Modeled Feeder Hosting Capacity



Source: Electric Power Research Institute, 2015. Ibid, Pg. 3.

Electric Vehicles (EVs) are an example of how values and costs of DER are determined by their location in the circuit. EVs can charge while demand for electricity is low, installed capacity is underutilized, or a surplus of cheap non-dispatchable renewable energy exists. Conversely, EVs charged at peak times increase demand and ramp-up needs. Therefore, it is essential to manage both the time and siting of EV charging. Even if EV penetration is not significant at the system level, adoption tends to come in clusters.[28] In the neighborhoods where clustering occurs, as little as two neighbors charging their cars with a 220 volt charger simultaneously could overload a distribution circuit transformer.[29]

There are many ways the utility can avoid negative effects and reap the benefits of DER. It can implement a variety of grid upgrades to reliably accommodate high penetration levels of DER. These upgrades include re-conducting, transformer upgrades or replacements, voltage regulators and capacitor banks, reconfiguration of protection schemes, advanced PV inverters, battery storage, convenient EV charging infrastructure, and smart technologies.[30] Such improvements to the system allow for better DER integration, visibility, and control along the distribution grid. Each of these upgrades benefits a different subset of stakeholders. The intricacies of evaluating the tradeoffs of integrating DER is discussed further in the section entitled "Considerations for Decision-Makers".

The utility must proactively integrate and deploy DER, rather than merely reacting to it. The utility will have to adapt their planning processes to reflect the new DER environment as they determine demand forecasts, requisite infrastructure, and incentive strategies. Specifically, the utility ought to:

- Model detailed scenarios in distribution circuits to determine the optimal siting of different DER technologies (thus maximizing the added value and minimizing the need for updates)
- Consider which type of DER (solar, gas-fired microturbines, etc.) is most appropriate for the service area's climate.
- Plan grid updates and integration of smart grid devices to increase hosting capacity and enable control of DER
- Establish incentives to guide the deployment of the DER such that the added value to the system is maximized
- Evaluate and update operating criteria and protection mechanisms considering DER implementation[31]

In some cases, the utility must actively monitor and manage DER to reduce the costs of accommodation.[32] Because the effects of DER will vary greatly within a utility based on the type and location of the DER, it is especially important that the utility and policymakers consider a variety of circumstances when deciding whether or not to incentivize different types of DER.

Effect of Distributed Energy Resources on Low-Income Consumers

DER deployment exposes low-income customers to a variety of financial risks. Though low-income customers generally consume less energy than the general population, energy costs make up a greater share of their total income.[33] Consumer advocates point out that low-income customers might be disproportionately impacted by DER because of the inability to take advantage of changing rate structures regarding DER pricing mechanisms, low energy efficiency/ lack of housing insulation, and the inability to afford DER. A number of programs across the country address aspects the negative impacts of DER penetration on low-income customers:

28 Garrett Fitzgerald et al, *Electric Vehicles and Distributed Energy Resources* (2016), Pg. 25.

29 Silver Spring Networks, *How the Smart Grid Enables Utilities to Integrate Electric Vehicles* (2013), Pg. 8.

30 Solar Electric Power Association and Black & Veatch, *Planning the Distributed Energy Future* (2016), Pg. 19.

31 Ibid.

32 Ibid.

33 Rocky Mountain Institute. Low Income Solutions in a High DER Future (2014), Pg. 3.

- Consolidated Edison's *Connected Homes Project* is an educational platform helping low income customers learn more about DER and engage in Demand side Management (DSM) programs.[34]
- National Grid's *Fruit Belt Neighborhood Solar Partnership* in New York promotes DG and EE efforts in low income neighborhoods by installing solar PV panels on 100 residential rooftops.[35]
- California Public Utilities Commission's *Single-family Affordable Solar Homes Program* provides financial assistance, job training, employment opportunities, and enhanced community engagement. Additionally, California's state government mandated that at least 10% of the California Solar Initiative funds be spent on energy programs which serve low income customers.[36]

REVENUE CHALLENGES AND OPPORTUNITIES

Changes in the electricity system are creating challenges and opportunities that the utility must manage. The proliferation of DER, for example, threatens the utility's traditional business model. Other developments, though, including the rise of electric vehicles and the digitalization of the grid, stand to either improve the utility's revenue or reduce its costs. Overall, the utility faces serious profitability obstacles in the next decade.

Distributed Energy Resource Valuation

Valuating DER is a complex undertaking. With varying stakeholders and even more varying priorities, reaching a fair and complete calculation that all sides can agree on is nearly impossible. However, DER valuation and compensation is one of the most, if not the most, crucial aspects of utility integration of DER. While this is a challenge for the utility, if structured correctly it can also be used to reduce costs and produce revenues.

34 Consolidated Edison Company of New York, *Distributed System Implementation Plan, Case 14-M-0101* (2016), Pg. 68.

35 National Grid, *Implementation Plan for Fruit Belt Neighborhood Solar REV Demonstration in Buffalo, New York, Case 14-M-010*1 (2016), Pg. 1.

36 California Public Utilities Commission, *Single-family Affordable Solar Homes (SASH) Program: Semi-annual Program Status Report* (2017).

This beneficial effect will follow a positive tendency up to a point. DER becomes less valuable as a result of these four factors: distance, market penetration, granularity of DER valuation, and the "greening" of the grid.

1) Distance between the end user and installed DER (in this case DG) is incredibly important because DG is most valuable when consumed on-site. This ensures no line losses occur and the grid infrastructure does not incur any undue burden. The value of DG decreases as the electricity generated moves along the grid, because of the line losses and physical impacts to the grid itself.
2) Market penetration levels also determine the value of DER, whether it is distributed generation, energy efficiency, energy storage, or demand response. In high penetration scenarios, there are increased risks of negative impacts on the grid system, and increased investment costs to grid in order to improve hosting capacity. Also, the capacity value of an individual DER goes down when it becomes "one of many." A California economic study concluded 30% penetration of distributed PV generation might be 65% less valuable than PV penetration at only 5% because the combination of PV penetration at 30% and baseload generation could strain the grid.[37]
3) By developing better granularity valuation, a utility is able to more effectively determine the location and orientation of each DER installation. Knowing these parameters, the utility can determine the unique value for each system. This would result in an uneven change in the value of the DER, with some increasing in value to the grid, and others decreasing.
4) "Greening" of the grid is the process by which carbon-intensive fuels are slowly phased out in favor of lower-emission fuels. One of the selling points of DER is its ability to cut an individual's carbon emissions, but this "greening" intrinsically chips away at the value of DER as installed systems will begin displacing low-carbon and renewable fuels rather than carbon-intensive fuels and processes.

37 Ibid, Pg.12.

These four factors demonstrate how the value of DER is not expected to always increase as adoption increases. As DER penetration levels increase, the grid reaches a point where it can no longer accommodate new DER without incurring in costs of upgrading grid infrastructure to ensure reliability of service. As system needs are satisfied by current DER deployment, new DER offers less value to the grid. For example, penetration of DG in one circuit could reach a point where the owners of that DG will still benefit from the energy produced by their device, but demand for the surplus energy might no longer exist in that circuit. DG must then be aggregated and be pushed further back onto the grid, but as distance increases and reaches customers with needs at the time of surplus generation, the value of that produced energy decreases. Similar constraints on value will be reached for energy efficiency, energy storage, and demand response as market penetration of these devices increase. As the utility incurs costs to upgrade the grid and accommodate high levels of DER, these costs will be reflected in the electricity bill of all customers, including those who do not own DER.

Value of Solar (VOS) Calculation: Minnesota and Austin incorporate a number of the same components into their VOS formula, such as avoided fuel and T&D costs, environmental benefits, line loss savings, and avoided capital costs. The value associated with each component might change over time because the benefits associated with an individual DG site decreases as the penetration of DG increases. For example, as the grid becomes greener, there comes a point where additional DER will not displace any more non-renewable energy sources. ***Figure 8*** below shows how switching to a VOST can save the utility money over the long run compared to traditional NM.

A utility with low penetration levels of PV is at an important point when considering how to value DER. For instance, a utility at this phase might incentivize PV through NM. However, once a distribution area reaches moderate to high level of DER, such an incentive might not be necessary. As net metering and other "smart" measures are incentivized, the utility will coincidentally become more expensive (see ***Figure 10***). Thus, regulators need to remain flexible and continuously revisit and reassess rate structures. This reassessment is also important when considering revenue generation for different types of utilities.

Distributed Energy Resources Compensation

DER adds a layer of complexity to the recovery of fixed costs, especially when it comes to renewable energy. Customers expect to be paid for the full value of their resource, including resiliency benefits, reduced peak capacity requirements, and environmental benefits. However, most utilities – and especially deregulated utilities – do not collect money for these aspects of their services, creating a "missing money" problem.[38] Traditional ratemaking is based on the cost to provide services, not based on the value provided by those services; asking the utility to pay for the full value provided by DER can result in utilities giving out more money than their avoided cost. Utilities whose policies include compensation for DER currently use either net metering or value of solar tariffs to calculate these values.

Net Metering

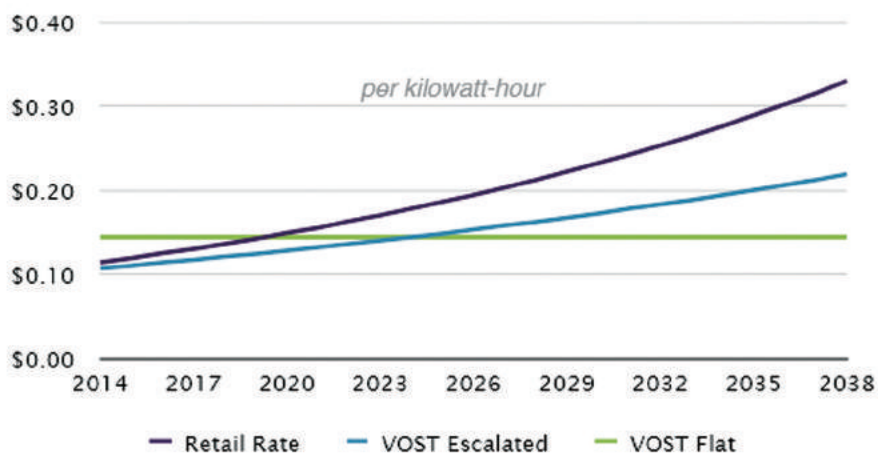
Net metering (NM) is a billing system that credits PV owners for the electricity they add to the grid. Customers are only billed for their "net" electricity usage, calculated by subtracting the customer's DER generation from their usage. This method of compensation values DG as providing equal value as the retail rate, which is transparent and easy for customers to understand. However, NM fails to properly account for the costs required to maintain grid and generation operations for each prosumer (a consumer that also produces electricity), a cost that is not recovered if the prosumer generated enough electricity to receive a zero bill or a credit from the utility. NM simply functions as a rough approximation of avoided costs. NM critics state that issues arise when there are high penetration levels of distributed sources connected to the system.[39]

38 Tierney, Pg. 16.

39 Thomas Hoff et al, *2014 Value of Solar Executive Summary* (2013), Pg. 10.

FIGURE 8:

Projected Net Metering Rate (Residential) Compared to Value of Solar Rate



Source: Institute for Local Self-Reliance, 2014. Farrell, Pg. 7.

To accommodate reduced demand due to PV production in the afternoons, grid operators ramp down production. In the evening, the sun sets, PV production slows and stops, right as demands are highest due to people arriving home and turning on appliances/air conditioning. Power plants must then ramp back up to meet the increase in demand. The ramp down and ramp up both come at an expense to the power plant that is passed on to utilities. Utilities in states such as Hawaii and California are already feeling the effects of ramping challenges because of increased penetration of distributed generation, specifically PV.[40] Without battery storage (and therefore the ability to flatten the load curve), NM customers might increase system costs, potentially causing cross-subsidies between PV customers with NM and customers without PV.[41]

Value of Solar

Net metering is widely credited for the recent massive adoption of distributed solar. However, utilities across the country are beginning to view NM as an imprecise tool for compensation; the true value of DER might be higher or lower than the retail rate, depending on a variety of factors.

40 For more information, see Denholm et al, *Overgeneration from Solar Energy in California: A Field Guide to the Duck Chart* (2015).

41 John Farrell, *Minnesota's Value of Solar: Can a Northern State's New Solar Policy Defuse Distributed Generation Battles?* (2014), Pg. 3.

The VOS is a relatively new mechanism for the utility to purchase distributed generation. A VOS rate is calculated by summing the major benefits (such as avoided capital costs and environmental/social benefits) and costs (such as those mentioned above) associated with PV to compensate PV generation in cents per kilowatt-hour (kWh). This method separates the costs of utility services from DER benefits and attempts to value them separately by compensating PV at its true value.

The VOS mechanism has only been adopted in Austin, Texas, and it is currently under development in the state of Minnesota. In Austin, the value of solar tariff (VOST) mechanism is a "buy-all sell-all" transaction; customers purchase all of their electricity needs at the applicable retail rate and sell all of their PV to the utility at the VOST rate, typically through a bill credit.[42] Another design option that has not yet been put into practice, is to apply the VOS rate only to excess generation sent to the utility (that is, to subtract out any generation that is consumed on-site).[43] On average, only 20-40% of customer sited PV generation goes onto the grid.[44]

To use VOS, the utility must be able to track both

42 Taylor et al, Pg. 5.

43 Tierney, Pg. 3.

44 Solar Energy Industries Association, "Net Metering".

TABLE 3:

Summary of Major Bill Credit Policy Changes and Proposed Changes

State	Status	Former Policy	New Policy	Grandfathering?
AZ	Proposed	Net metering	Net billing: self-consumption with all exports to the grid credited at the utility-scale renewable energy purchase rate	✓
HI	Enacted	Net metering; net excess credited at retail rate	Net billing: self-consumption with all exports to the grid credited at avoided cost ("grid-supply" tariff option)	✓
NV	Enacted	Net metering; net excess credited at retail rate	Net billing: self-consumption with all exports credited at avoided cost	X
CA	Enacted*	Net metering; net excess credited at retail rate	Net metering: net excess credited at retail rate, but customer pays non-bypassable charges ($0.02-$0.03/kWh) on all grid imports	✓
SC	Enacted	No policy	Net metering: net excess credited at retail rate; utility net metering tariffs approved in 2015	✓
MS	Enacted	No policy	Net billing; all excess credited at avoided cost, plus $0.025/kWh for "non-quantifiable expected benefits"	N/A
LA	Proposed	Net metering; net excess credited at retail rate	Net billing; all excess credited at avoided cost	X
LA (Entergy)	Effective 1/1/2016	Net metering; net excess credited at retail rate	Buy-all, sell-all at avoided cost rate	✓
LA (SWEPCO)	Effective 2/1/2016	Net metering; net excess credited at retail rate	Net billing: self-consumption with all exports credited at avoided cost	✓
VT	Proposed	Net metering, plus performance-based incentive: net excess credited at retail rate	Net metering: net excess credited at retail rate plus $0.02/kWh siting incentive and $0.03/kWh REC premium (if applicable)	✓

Source: The N.C. Clean Energy Technology Center, The 50 States of Solar: A Quarterly Look at America's Fast-Evolving Distributed Solar Policy Conversation (2015), Pg. 10.

how much electricity the customer is using and how much electricity the customer is generating. This two-way metering can either be done with two separate meters or with one bi-directional meter that can measure the electricity delivered and the electricity received separately.

The figure suggests the retail rate will generally be higher than the VOST, meaning the utility will save money by paying PV customers the VOST rate instead of the retail rate.

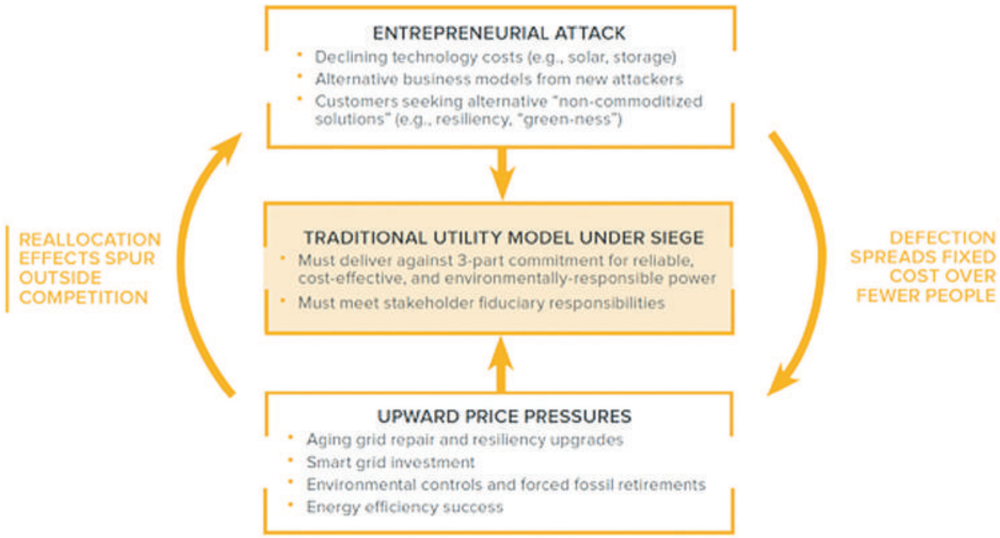
The biggest difference between Austin Energy's VOST and Minnesota's VOST is that Austin Energy's VOST rate changes annually, while a Minnesota's VOST rates are updated annually, the prosumer receives the current VOST rate, locked in for 20 years. In Austin, all prosumers will see a lower VOST as penetration increases but as penetration increases in Minnesota, established prosumer's rates will not change, but new prosumers will receive a lower rate. Because utilities are more familiar with Minnesota's existing net metering program and routine ratemaking procedures, utilities in Minnesota are reluctant to opt for VOST. Vermont[45] and Maine[46] also investigated a VOS rate using very similar variables and values, but those states found the true value of PV to be nearly double the retail rate; therefore, neither Vermont nor Maine chose to implement VOS rates. A number of states and utilities are examining their methods of DG compensation.

45 Jamie Howland et al, *Value of Distributed Generation: Solar PV in Vermont* (2015), Pg. 8.

46 Benjamin Norris et al, *Value of Solar Study* (2014), Pg. 13.

FIGURE 9:

Pressures DER Puts on Traditional Utility Business Models



Source: Rocky Mountain Institute, The economics of Grid defection, 2014. Ibid.

Table 3 summarizes policy changes implemented to mitigate issues with NM.

VOS Methodology used for Other Forms of DER: In principle, the methodology for determining the value of solar can also be used to calculate the value of other resources as well. Value-based compensation will provide the utility a comparison with which to make resource planning decisions and might be used to set the values for all types of renewables.

In conclusion, it is in the utility's best interest to begin the transition from net metering to a value of solar methodology before penetration levels increase. VOS promotes new PV in areas that have low or no penetration by offering the first prosumers the most value for their services, and VOS more appropriately values the services PV provides. Right now, DG's pecuniary costs on the grid are relatively low due to its low penetration, but these costs could increase as penetration increases. Conversely, some of the benefits provided by DG are highest at low levels of penetration. Once an area already has high levels of DG, installing PV on an individual customer's roof primarily benefits the prosumer and provides significantly less value to the utility since the utility has already offset a significant amount of demand with DER. The value of DG might therefore be at its highest point today due to the low levels of penetration.[47]

Utility Death Spiral

High DER penetration can disrupt the utility's traditional business model that charges the customer a price per kilowatt-hour of electricity that allows for the recovery of fixed costs, operation expenses, and a reasonable rate of return on their prudently made investments.[48] Large deployment of DER can increase the costs and reduce the revenues of the utility, endangering the sustainability of the traditional business model. The threats include:

Stagnant electricity demand, due to demand-side management strategies and energy efficiency efforts

- Adoption of DER, facilitated by falling costs and the incorporation of net metering policies and energy storage
- The development of competing business models[49]

47 Taylor et al, Pg. 11.

48 Darryl Tietjen, "Tariff Development: Review of the Basic Ratemaking Process".

49 Rocky Mountain Institute, *The Economics of Grid Defection* (2014), Pg. 11.

The combination of these events creates a cycle of increasing costs and decreasing revenues that has been called the "utility death spiral." The cycle begins with the utility experiencing decreased revenues and increased expenditures related to DER deployment. The utility subsequently submit rate cases to increase retail electricity prices to cover costs. Higher electricity prices provide an additional incentive for ratepayers to invest in DER to use less electricity, further reducing the utility revenues and decreasing its customer base. Reduced electricity consumption and grid defection would consequently lead to another rate case and the allocation of fixed costs over fewer customers. This causes even higher prices for remaining customers, perpetuating this death spiral. ***Figure 9*** is a visualization of this cycle.

The magnitude of the impact of loss of revenue due to the "death spiral" will be different for vertically integrated utilities than restructured utilities. For instance, a utility that is vertically integrated might see an overall large loss in revenue generation as they see a large increase in the required updates, while also having to recover costs for assets (generation plants, transmission lines, distribution lines, etc.).[50]

Reduced profits due to the death spiral might also reduce the utility's access to capital markets. Credit quality for a company is assigned according to its expected profits. A company with a lower expected profit and therefore a bad credit rating will face a significant cost, hence paying a high return for investors. Historically the utility has obtained relatively low-cost capital because investors trust the utility will earn a fair and secure return from their reliable customer base, resulting in low borrowing rates. The presence of DER, currently less than 1% of load, is not significant enough to make investors consider its effect in valuations.[51] However, in states like New York and Hawaii, DER technologies will reach a grid-parity status in the next two decades.[52]

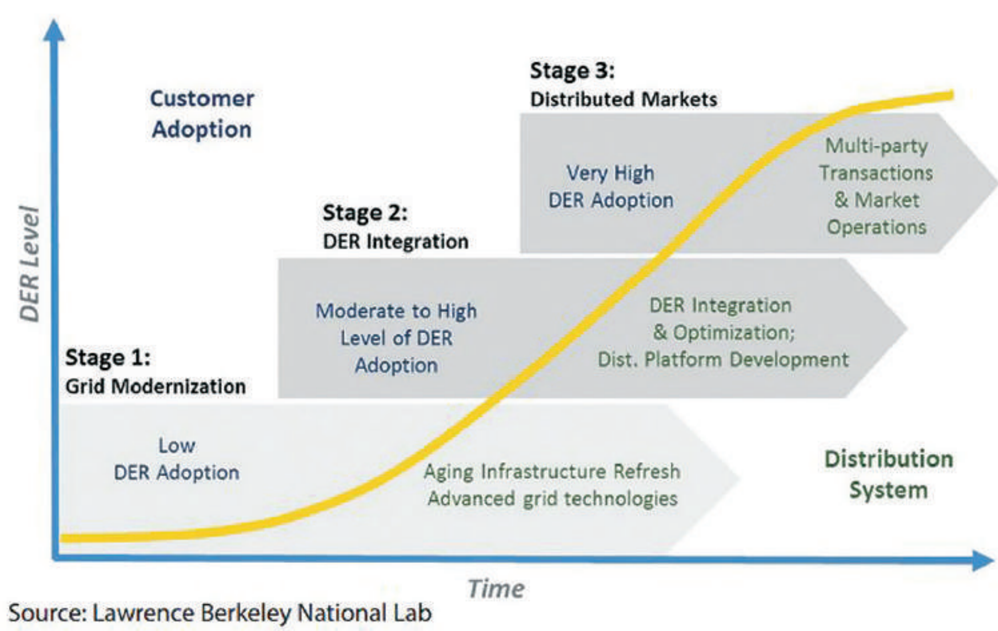
50 Ibid, Pg. 63-65.

51 Peter Kind, *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business* (2013), Pg. 1.

52 Peter Bronski et al., *The Economics of Grid Defection: When and Where Distributed Solar Generation Plus Storage Competes with Traditional Utility Service* (2014), Pg. 3.

FIGURE 10:

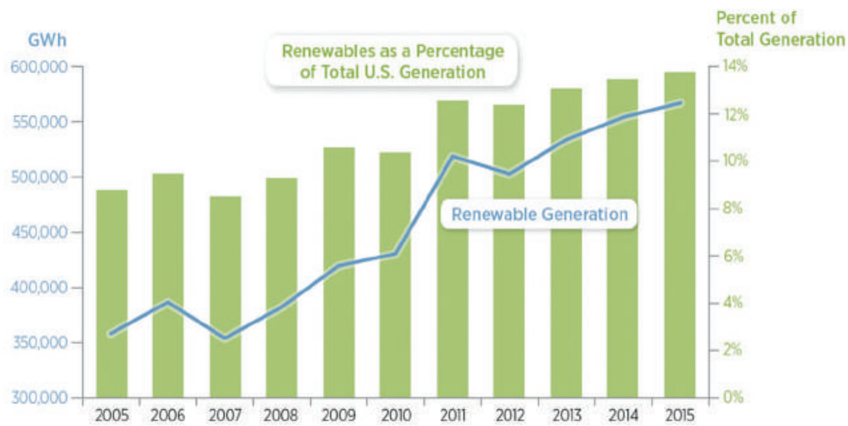
DER Adoption Curve



Source: The National Association of Regulatory Utility Commissioners, Distributed Energy Resources Rate Design and Compensation (2016), Pg. 60.

FIGURE 11:

Renewables as a Percentage of Total U.S. Generation



Source: Philipp Beiter and Tian Tian, Renewable Energy Data Book (2016), Pg. 26.

To manage risks related to DER, the National Association of Regulatory Utility Commissioners (NARUC) strongly recommends regulators and the utility monitor DER adoption closely. Lawrence Berkeley National Labs (LBNL) identifies three stages of DER adoption: 1) Low DER Adoption, 2) Moderate to High DER Adoption, and 3) Very High DER Adoption. In the low DER stage, the utility still invests in grid updates. The distribution grid moves to stage 2 when DER adoption is 5% of the distribution grid peak load. Stage 3, very high DER, begins when the utility must invest for transactional energy to occur. ***Figure 10*** illustrates the three states of DER adoption.

Prospective Cost-Cutting and Revenue Sources Renewable Electricity

In the past decade, there have been substantial changes to the overall fuel mix of the U.S. electricity sector.[53, 54] The advent of the shale revolution led to a glut of inexpensive natural gas that has recently displaced coal in electricity generation.[55] Meanwhile, Renewable Portfolio Standards (RPS) have further contributed to a rise in utility-scale renewable generation that has been spurred on by government subsidies and incentives.[56, 57] Once installed, these low-carbon resources generate electricity with zero fuel cost, often displacing more expensive and carbon-dense fuels.[58] ***Figure 11*** shows the increase in generation from renewables relative to total generation.

Digitalization of the Utility

The digitalization of utilities presents a range of opportunities for the industry, assuming it proactively integrates new technologies into existing structures. Holding significant potential for new product and management options, the "Internet of Things" and its capacity to aggregate data is a central driver of this progression. Smart meters and the smart grid, digital productivity tools for employees, and automation of back-office processes are forecasted to create an opening for improved operations and increased flexibility along the value chain from generation to customer relations. According to a study by McKinsey & Company, "conservative estimates supported by analysis of real-life cases suggest that digital optimization can boost profitability by 20 to 30%."[59]

53 EIA, "Natural Gas, Renewables Projected to Provide Larger Shares of Electricity Generation - Today in Energy U.S. Energy Information Administration", Published May 4, 2015.

54 EIA, "The Mix of Fuels Used for Electricity Generation in the United States Is Changing", Published November 8, 2013.

55 Ibid.

56 NREL-SAPC, *Solar Securitization: A Status Report* (2013), Pg. 2.

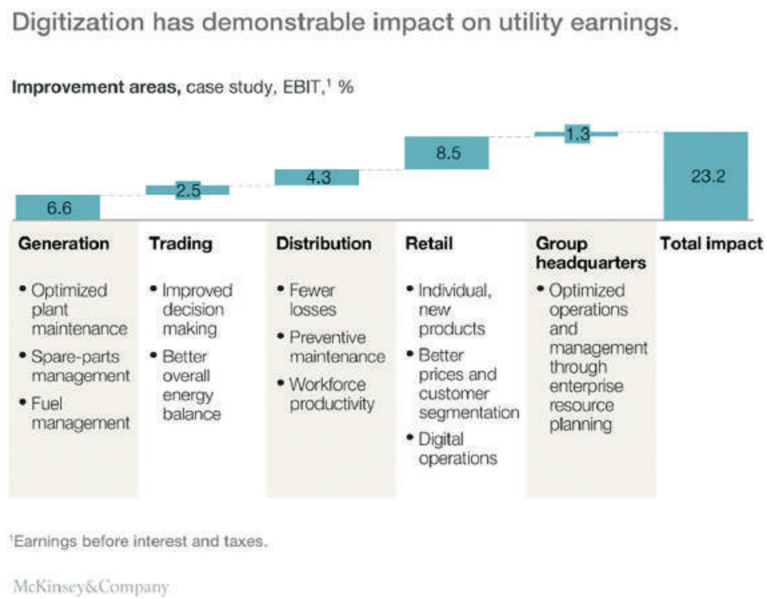
57 Solar Energy Industries Association, *Solar Industry Data* (2017).

58 EIA, "The Mix of Fuels Used for Electricity Generation in the United States is Changing", Published November 8, 2013.

59 Adrian Booth et al., "The Digital Utility: New Opportunities and Challenges", Published May 1, 2016.

FIGURE 12:

Digitalization's Demonstrated Impact on Utility Earnings



Source: McKinsey & Company, Ibid, Pg. 14

Distribution System Platforms

Distributed System Platforms (DSP) have received a lot of recent attention as a prospective revenue sources for the utility. DSP is intended to "smoothly integrate innovative energy services and solutions onto the existing grid, allowing them to compete on equal footing with electricity from centralized power plants," according to Elizabeth Stein of Environmental Defense Fund.[60] The model is designed to incentivize the utility to consider the integration of third-party DER vendor's products onto the grid as an alternative to traditional investments in generation infrastructure, a historic revenue-generator for the utility. To offset revenue losses, the DSP model triggers an adjustment of the traditional rate formula, permitting the utility to profit as platform operators. The utility would receive revenue as an intermediary that connects energy consumers and retailers, in a manner akin to how Uber levies a surcharge for providing of means for riders and drivers to connect.

While each DSP will have unique revenue structures, pricing is expected to reflect the new dynamics of the market, including needs for quality, elasticities of demand, environmental and service preference, ability to provide services as resources, increased volatility, availability of more granular data, etc.[61] DSP operators might receive rents (be it subscription-based, transaction-based, or marginal cost pricing) from one or both sides of the market: electricity generators and consumers. The utility might also be compensated for entering insurance contracts with the owners of a distributed energy installations in case of an outage. Lynne Kiesling of Northwestern University explains that such an arrangement would require a wires backup. Therefore, the insurance charge could be the cost of electricity in addition to a wires charge.[62]

There are several reasons the platform model might have limited applicability to DER deployment in distribution utilities:

1. Successful platforms usually collect revenue from both the customer and provider of the service the platform enables. With the small amount of electricity involved in residential transactions, the utility will struggle to

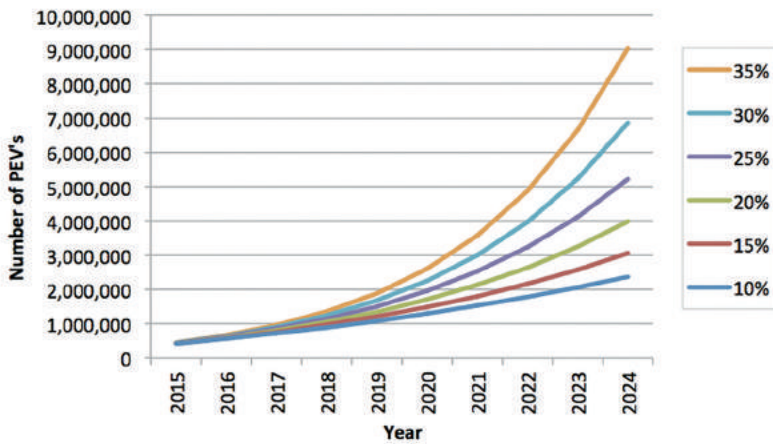
60 Elizabeth B. Stein, "Utility 2.0: New York State Envisions New Platform Giving Equal Priority to Clean Energy Solutions", Published October 15, 2014.

61 Pollitt and Weiller, Pg. 20-21.

62 Kiesling, Pg. 17.

FIGURE 13:

EV Fleet Growth Forecast



Source: David Block and John Harrison, Pg. 6.

find customers willing to pay a high enough premium to cover its costs.

2. New products and services developed for the platform do not generate revenue for the utility. NEST thermostats and energy management systems benefit, for example, reduce utility revenue.

3. A platform model grows when more customers use the platform. A utility, however, is bound to a service area, and cannot grow its consumers outside that designated area.

4. In accordance with Metcalf's Law, the value of the platform increases with the number of interconnections, allowing the business to charge a premium for access to the platform. However, the utility cannot charge a premium for access to the grid. A utility can only charge an interconnection fee, which reduces the potential revenue generated by the platform.

5. The network effect does not apply to DER expansion. Growth of one side of the network (e.g. DER) does not lead to growth on the other side of the network (e.g. utility generators, consumers).

All of these factors result in limited potential for platform system revenues. Additionally, PV markets will be affected by seasonality, and the volume of transactions will vary greatly depending on geographic location. Distribution markets might not develop into mature, robust markets, which will limit the utility's transaction fees.

Electrification of Transportation

The electrification of transportation is one of the largest potential revenue streams for the utility. Forecasters anticipate significant growth in sales and fleet deployment of electric vehicles EVs over the next several decades. In 2015, approximately 115,262 EVs were sold in the U.S., with a total fleet of 400,000 EVs.[63] Using historical sales data, Electric Vehicle Transportation Center (EVTC) plotted expected yearly and cumulative EV sales until 2023 across growth-rate intervals from 10% to 35%. ***Figure 13*** highlights the forecast range.

Several forecasters made similar projections to those of EVTC for fleet deployment in the early 2020s. Beyond the 2020s, estimates begin to vary widely. ***Table 4*** summarizes some of the major projections of fleet deployment up to 2050.[64] The rise of EVs is projected to result in increased electricity demand from about 20,000 to 390,000 GWh by 2040, according to the U.S. Department of Transportation.[65]

63 David Block, Prediction of Electric Vehicle Penetration (2014).

64 Federal Highway Administration, *Feasibility and Implications of Electric Vehicle Deployment and Infrastructure Development* (2015), Pg. 65.

65 Ibid, Pg. 67.

TABLE 4:

EV Fleet Deployment Projections

Organization	Publication	Prediction	Year
Center for Entrepreneurship & Technology at the University of California	Electric Vehicles in the United States - A new model with forecasts to 2030	8-21 M 180-240 M	2020 2050
Energy Information Administration	Annual Energy Outlook 2013	1 M 6.32 M	2020 2040
The Electric Power Research Institute	2012 COG EV Taskforce presentation	2.5 M – 8 M 12.5-50 M	2020 2030
Electric Vehicle Transportation Center at the University of Central Florida	Electric Vehicle Sales and Future Projections	1.17 M – 2.84 M 1.86 M – 7.3 M	2020 2023
National Academy of Science	Transitions to Alternative Transportation Technologies - Plug-in Hybrid Electric Vehicles	1 M 100 M	2020 2050

Source: Multiple; see publication column

Another potential revenue stream for the utility related to EVs is the deployment of public charging infrastructure. Though the business opportunity is in its infancy, a pilot project in California might shed light on its viability. In 2016, California's Public Utilities Commission (CPUC) approved proposals from its three investor-owned utilities (IOUs) to invest ratepayer money in EV charging stations. Southern California Edison's "Charge Ready" program will build 1,500 charging stations for $22 million, San Diego Gas and Electric is set to deploy 3,500 units at 350 businesses and multifamily homes for $45 million, and Pacific Gas and Electric will install 7,500 charging stations for $160 million.[66] The success of the pilot will determine whether all three utilities would scale up deployment of EV charging infrastructure in the future.

The deployment of charging infrastructure might present new revenue opportunities for the utility in high EV penetration areas, but the politics of seeking rate-basing for infrastructure might pose challenges. CPUC had initially banned the utility from investing in EV charging infrastructure due to the anti-competitive effect it might have on the market. It reversed the decision after a market for public charging infrastructure failed to materialize, given that the business case for selling electricity via public infrastructure was not strong enough to attract third-party vendors. To meet the state's climate and clean energy goals, policymakers and regulators chose to allow the utility to participate in the initiative. Nevertheless, stakeholders remain apprehensive about the extent to which the utility should be involved in public charging infrastructure. Ambivalence as to the proper role of the utility in the development of public charging infrastructure, however, might result in this revenue stream being more robust in some energy markets.

Indoor Agriculture

The emergent indoor agriculture industry is another important source of new revenue for the utility. The industry's energy consumption, however, might also be its greatest defect. Dr. Louis Albright, an emeritus professor of biological and environmental engineering at Cornell University, illustrates this point with wheat. At $0.10 per kilowatt-hour, one loaf of bread made of wheat grown indoors would cost about $23 in electricity usage.[67] Until technology reduces the energy

66 Michelle Melton, "Utility Involvement in Electric Vehicle Charging Infrastructure: California at the Vanguard", Published April 6, 2016.

67 Stacey Shackford, "Indoor Urban Farms Called Wasteful, 'Pie In The Sky'", Published February 19, 2014.

TABLE 5:

Cost Effectiveness Tests

Test	Key Question	Approach Summary
Participant cost test	Will the participants benefit over the measure?	Comparison of costs and benefits of the customer installing the measure
Program administrator cost test	Will utility bills increase?	Comparison of program administrator costs to supply-side resource costs
Ratepayer impact measure	Will utility rates increase?	Comparison of administrator costs and utility bill reductions to supply-side resource costs
Total resource cost test	Will the total costs of energy in the utility services territory decrease?	Comparison of program administrator and customer costs to utility resource saving
Societal cost test	Is the utility, state, or nation better off as a whole?	Comparison of society's costs of energy efficiency to resource savings and non-cash costs and benefits

Source: Modified from Environmental Protection Agency, *Understanding Cost Effectiveness of Energy Efficiency* (2008), Pg. 2-2.

cost of indoor food production, it's unlikely the industry will realize its potential market share.

While the business case for the indoor production of food is uncertain, the legal cannabis industry is booming. A report by New Frontier and ArcView Market estimates the industry at $7.1 billion in 2016, a 26% growth over the previous year.[68] The year 2016 also brought political victories for the cannabis growers and investors, as California, Maine, Massachusetts, Nevada, and Arizona joined Colorado and Washington State in legalizing recreational marijuana. Arkansas, Florida, Montana, and North Dakota voted to legalize medicinal marijuana in 2016 as well.[69] If states continue to legalize recreational cannabis on a one-off-basis, GreenWave Advisors projects the industry will reach $25 billion by 2020; in the event of full legalization at the federal level, forecasters expect the industry to reach $35 billion.[70]

The legal cannabis industry uses a prodigious amount of electricity. An Energy Associates study, conducted in 2011, found "each four-by-four-foot production module doubles the electricity use of an average U.S home... [the added electricity demand is] equivalent to running about 90 refrigerators."[71]

The industry's electricity use at the time of the study was equivalent to 1% of national electricity consumption overall, or 2% of that of households.[72] Roughly 20% of overhead of indoor marijuana operations is related to electricity use, resulting in energy expenditures of $6 billion each year. This is the electricity equivalent of two million average U.S. homes.[73, 74]

CONSIDERATIONS FOR DECISION-MAKERS

The best way for any single utility to incorporate DER will depend on individual characteristics of that utility and its service area. This section provides an overview of the costs and benefits of DER, how to plan for the deployment of DER (including infrastructure upgrades and ratemaking reform), and an overview of commonly used subsidies and incentives.

Costs and Benefits to Utilities

The California Standard Practice Manual identifies methodologies for estimating benefit-cost analysis. Evaluating the diversity of stakeholder interests, the five tests help ratepayers and program managers evaluate program costs and effectiveness. To perform a benefit-cost analysis, a program's net present value benefits are divided by the

68 The Arcview Group and New Frontier, *The State of Legal Marijuana Markets* (2016), Pg. 1.

69 Normal, "Normal Election 2016 Marijuana Ballot Results", Undated.

70 Matthew A. Karnes, *State of the Emerging Marijuana Industry Current Trends and Projections* (2015), Pg. 2.

71 Evan Mills, *The Carbon Footprint of Indoor Cannabis Production* (2012), Pg. 9.

72 Ibid.

73 Melanie Sevcenko, "Pot is Power Hungry: Why the Marijuana Industry's Energy Footprint is Growing", Published February 27, 2016.

74 Mills, Pg. 10.

costs incurred over the life of the evaluation.[75] Stakeholders value benefits and costs differently and might use specific tests to assess cost-effectiveness. The Manual encourages comparing results of different tests and utilizing a multi-perspective approach to balance tradeoffs. Adoption of the tests has become widespread among policymakers analyzing the effects of prospective decisions.

EPRI's Integrated Grid methodology and framework first categorizes a cost or a benefit as a distribution system impact, a bulk system impact, a customer impact, or a societal impact, allowing the utility to tailor a study to their own circumstance (vertically integrated vs. distribution-only, etc.).[76] The distribution system impact and bulk system impacts are then aggregated into a change in the utility cost.

75 California Public Utilities Commission, *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects* (2001), Pg. 4.

76 *The term bulk power system here is referring to both the generation and transmission sectors.*

EPRI provides a methodology for identifying the most beneficial locations for DER in their report *The Integrated Grid: A Benefit-Cost Framework*. They also provided a preliminary summary of possible benefits and costs that are featured in ***Table 6***.[77]

In a separate analysis, the Rocky Mountain Institute (RMI) explores two financial issues that might become a cost or benefit depending on their effect on the individual system: a) fuel price hedge (the cost the utility should have covered to guarantee a fixed cost for its fuel) and b) market price response (the effect of reducing electricity prices by lowering the demand of centrally-supplied electricity).[78]

Ratemaking Reform

As is shown in ***Figure 14*** below, utility credit ratings have decreased from 1970 to 2011. Lower

77 EPRI. *The Integrated Grid: A Benefit-Cost Framework* (2015), Pg. 9-6.

78 Rocky Mountain Institute, *A Review of Solar PV Benefit & Cost Studies* (2013), Pg. 16.

TABLE 6:

Impacts of DER Accommodation and Possible Benefits and Costs

Element	Impacts	*Benefit*	*Cost*
Distribution	Loss Reduction	x	
	Capacity Upgrade Deferral	x	
	Reconductoring		x
	Line Regulators/STATCOMS		x
	Relaying /Protection		x
	LTC accelerated wear		x
	Voltage upgrade		x
	Smart Inverters	x	x
	O&M		x
Bulk Power System	Generation Mix/Requirement Changes	x	x
	Deferral of Transmission Upgrades	x	
	Transmission losses	x	
	O&M	x	x
	Fuel Savings	x	
	Congestion	x	
	System Operations/Uncertainty		x
Customer	DER Investments		x
Societal	Emissions - CO2/GHG, Hg, SOx, NOx	x	
	Cyber Security	x	
	Health	x	
	Macroeconomic effects	x	

Source: EPRI, 2015. Ibid.

credit ratings necessitate higher interest rates for investors, making it more expensive for the utility to make capital improvements.

As DER penetration increases and revenue becomes less reliable, investors will require an even higher rate of return, which will make investment plans even more expensive. A higher cost of capital will have to be shared among remaining customers in the form of higher utility rates, potentially contributing to a "death spiral" situation.

Performance-Based Ratemaking (PBR) provides a future that better incorporates DER because it shifts utility and shareholder incentives from capital investment and sales to targets of the regulator's choosing. This is done by untying utility revenues from their costs and/or sales and instead tying revenues to performance targets.

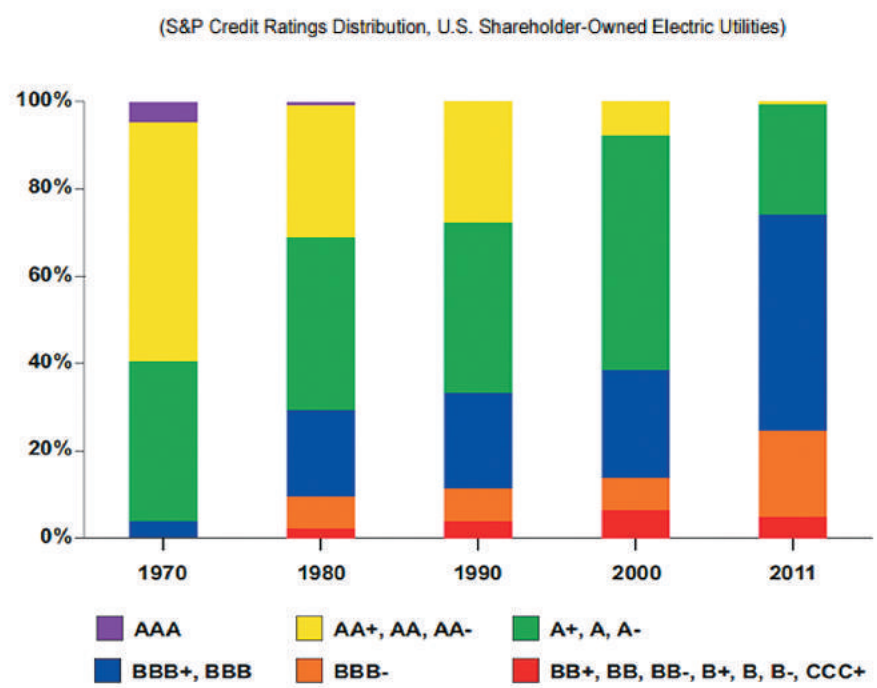
In the most general form, performance-based ratemaking refers to multiple ratemaking elements implemented together or individually that are intended to enhance utility performance incentives. It is a form of ratemaking that shifts financial incentive from selling electricity to achieving certain performance targets such as DER targets, higher reliability, and lower spending. A simplified form of the revenue requirement under PBR is slightly different than the revenue requirement under the COS model:

Revenue Requirement = Operating Costs + Depreciation Costs + Taxes + (Rate Base x Rate of Return) + Performance

Performance here is in the form of net income. It can be positive in case of a reward or negative in case of a penalty. However, this is a simplified model that does not capture the whole effect of performance-based ratemaking. Although there are PBR elements that provide direct income incentives, other PBR elements can encourage performance either through not incentivizing rate base growth or through allowing a higher regulated

FIGURE 14:

Electric Utility Industry Credit Ratings Distribution Evolution



Source: *Edison Electric Institute, 2013.* Kind, Peter, Pg. 10.

TABLE 7:

Incentive Structure: COS vs. PBR

Action	Traditional Cost of Service	Performance-Based Ratemaking
Capital Investment	Incentive to increase rate base through increasing spending on fixed assets	Incentive to cut back on capital spending through MRPs, ESMs, and PIMs
Operating Costs	No incentive to reduce operating costs as they receive little prudence in rate cases	Incentive to reduce operating costs through MRPs
Energy Sales	Incentive to increase sales: Throughput incentive	Disincentive to increase sales through decoupling (revenue regulation)
Innovation	No incentive to adopt innovative technologies	Can be incentivized through PIMs or through MRPs if innovation reduces costs
Risk	No incentive to reduce risk (customers bear risk)	Incentive to avoid risk (the utility bears risk)
DER	Can be incentivized if DER investment is added to rate base	Incentive for DER through MRPs, ESMs, and PIMs

rate of return. The following constitute the main mechanisms under which performance-based ratemaking might be applied:

- **Revenue Regulation:** Allowing the utility to recover the revenue requirement regardless of actual energy sales. If the utility sells less than expected on a given year, it is allowed to increase rates the following year to recover foregone revenues and vice versa.
- **Price and Revenue Caps:** Setting a cap on utility prices or revenues over a fixed period.
- **Rate Case Moratorium:** Fixing an extended period of time between rate cases. Usually implemented with price or revenue caps.
- **Attrition Relief Mechanisms:** During a price or revenue cap, automatic adjustments can occur to account for inflation, productivity increases, and customer growth, separately from a cost tracker.
- **Earnings Sharing Mechanisms (ESMs):** Forcing the utility to share surplus earnings or deficits with customers if their actual return on equity falls outside of a range of authorized returns.
- **Performance Incentive Mechanisms (PIMs):** Rewarding or penalizing a utility based on reaching specific target metrics prompted by policy goals. This can take different forms such as a direct financial incentives (income) or higher rates of return.

Several of these elements are often implemented together to get improved performance outcomes. For instance, one comprehensive example of performance-based ratemaking is multi-year rate plans (MRPs). MRPs involve a rate case moratorium implemented with a price cap, an attrition relief mechanism to adjust the revenue, and several performance incentive mechanisms.[79] In addition to fixing incentive issues in the cost of service model, performance-based ratemaking helps reduce regulatory costs by reducing the number of rate cases, which are often long and costly.

Performance-based ratemaking must be designed carefully in order to achieve desired outcomes. Strong cost-cutting elements in PBR might cause lower service quality from utilities who want to contain costs and save money. However, service quality and other targets can be addressed in

79 Lowry, Mark N., et al., *Performance-Based Regulation in a High Distributed Energy Resources Future* (2016), Pg. 1-15.

PIMs to resolve these issues. PIMs also need to be designed carefully since some performance targets can be hard to implement.[80]

Customer bills are shaped with the following price characteristics in mind: Volume-Based, Time-Varying, and DG. Volumetric subcategories are block rates, demand charges, and net metering. Time-varying subcategories include peak, real time, and seasonal. Peak rates charge customers more per kWh based on the time of day used. For instance, customers are charged the highest rates from 5-7PM, when demand is highest. In real time scenarios, customers use smart meters (or any other variety of immediately available price signals) to determine the instantaneous cost of electricity. Seasonal rates prescribe pricing changes based on the time of year. DG pricing initiatives include minimum bill, straight fixed, and exit fees.

Jim Lazar's 2015 "Smart Rate Design" drastically reimagines rate design in terms of modern needs and challenges. Lazar's three principles intentionally encourage maximum use of a variety of utility producing goods, such as alternative energy forms. Electricity use is decreasing, and the utility charges increasingly higher costs to compensate for lost revenue.

Lazar's principles combat this dilemma. First, he posits that customers should only pay for grid connection and should not be charged for externalities such as long term maintenance or social goods. If a person is connected to the grid, they should pay for the product received and nothing more. Second, customers should be charged prices proportional to "how much they use and consume." This measure is seen in inclining block rates, in which larger blocks of electricity usage are charged higher rates – similar to the structure of a progressive tax. For example, customers should receive price signals and be informed of the cost of electricity at any given moment. Customers might use less energy in peak-use hours if forced to pay more for electricity.

The third principle suggests compensation for those customers who supply electricity back onto the grid. This alludes to reimbursements, such as Austin's VOST, in which prosumers contribute energy back onto the grid for general use and consequently pay lower electricity bills.[81]

The most recent embodiment of the new ideas surrounding rate design reform is New York's Reforming the Energy Vision (NY REV). This program is fundamental to our understanding of future rate design application because of their palpable application of previously disparate principles. Their nine rate design principles rely on past thinkers such as James Bonbright and allude to the inherently political nature of providing public goods.

1. Rates must reflect current use and future costs.
2. Rates should incentivize political initiatives, such as reduction in carbon emissions and the need to curb energy usage overall.
3. Rates must be understandable and definable, not amorphous and difficult to decipher.
4. Rates must enable seller and consumers to make the right decisions: Sellers should continue to provide goods, and consumers should use electricity such that energy requirements will remain steadily predictable.
5. The utility should be appropriately compensated for goods produced, and the consumer should receive quality products.
6. A customer's ability to choose is central and will enable the long-term viability of all electricity producing enterprises.
7. Rates must be stable and predictable.
8. All people should have access to electricity, regardless of their position in society, as electricity is a public good.
9. Any changes to pricing must be gradual.[82]

80 Ibid, Pg. 15-25.

81 Lazar, Jim, and Wilson Gonzalez, *Smart Rate Design for a Smart Future* (2015), Pg. 6.

82 Energy Environmental Economics, *Full Value Tariff Design and Retail Rate Choices* (2016), Pg. 33-34.

Subsidies and Incentives

Subsidies and incentives have contributed to a rise in renewable generation.[83, 84] What constitutes a subsidy or incentive is a cloudier subject than one might expect. While sometimes used interchangeably, subsidies and incentives are by definition different. Generally, any form of financial support (grants, tax credits, loan guarantees, etc.) is referred to as a subsidy.[85] In the utility business model context, a utility, state, local, or federal government uses these subsidies to incent (encourage) customers to perform some action, such as to install solar PV generation or make efficiency upgrades. The energy industry has always received significant support through federal, state, and local subsidies. While an in-depth discussion of subsidies and incentives is not in the purview of this paper, a basic understanding of incentive methods is necessary to assess the effectiveness of the varying utility business models' ability to incentivize DER.[86]

- **Direct Expenditures:** Usually in the form of grants, direct expenditures are cash payments made directly to individuals or organizations to fund projects meeting certain criteria
- **Tax Preferences:** Reductions in tax liabilities such as production and investment tax credits[87]
- **Renewable Energy Credits (REC):** Tradeable credits based on electricity production, usually based on a Renewable Portfolio Standard (RPS)[88]
- **Loans/Guarantees:** Direct loans or loan guarantees intended to decrease the cost of capital
- **Net Metering:** A billing method allowing customers with their own generation to have their meter "run backward" in times of excess electricity production, crediting their bill
- **Value of Solar Tariff:** Similar to net metering, but the rate at which electricity fed to the grid is compensated at is fully evaluated and determined based on its value to the grid, instead of at the retail rate

Other actions, such as legislation or policy aimed at encouraging certain technologies or rebate programs for energy efficient appliances, can also be considered subsidies. These broad categories might imply that subsidy programs are easily compared, but not all subsidies are created equal. For example, a REC in one state does not always have equal value, nor is it exchangeable for, a REC in another state.

Who collects the financial rewards of subsidies varies by the type of resource and ownership arrangements; thus, the subsidy must be finely crafted to produce the intended result. In distributed generation such as rooftop PV, tax incentives and renewable energy credits might go to the homeowner or might go to a leaseholder if the installation is part of a power purchase agreement. There are advantages to third-party aggregation of benefits since a distributed generation company is much more likely to be able to market complicated instruments like renewable energy credits and might have a larger tax burden, therefore enabling the use of a larger tax credit. From the total federal energy expenditure pool, individuals collect over $18 billion, energy companies receive about $52 billion, and the other $32 billion goes to renewable energy companies.

In the short term, federal financial support for electricity generation will continue to grow as tax expenditures for renewables, specifically production tax credits, are projected to triple.[89] ***Figure 15*** demonstrates the large impact of the American Recovery and Reinvestment Act (ARRA) and the continuing increases in wind and solar spending. As shown in ***Figure 16***, the production tax credit, which subsidizes electricity sold, represents more than 95% of all federal support for wind.[90]

83 NREL-SAPC Working Group, *Solar Securitization: A Status Report* (2013), Pg. 2.

84 Solar Energy Industries Association, *Solar Industry Data*, (2017).

85 Griffiths, Benjamin W., et al., *Federal Financial Support for Electricity Generation Technologies* (2016), Pg. 7.

86 Congressional Budget Office, *Federal Support for the Development, Production, and Use of Fuels and Energy Technologies* (2015), Pg. 3.

87 *Tax preferences are the most common due to political palatability.*

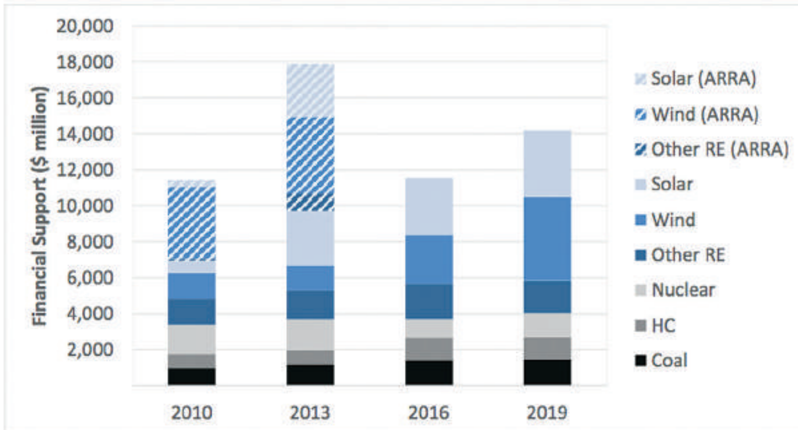
88 *Sometimes known as Solar Renewable Energy Credits or SRECs*

89 Griffiths, Pg. 6.

90 Ibid, Pg. 19.

FIGURE 15:

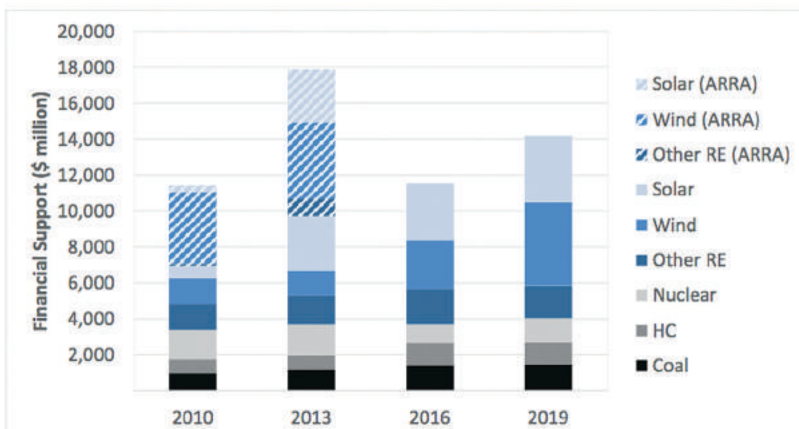
Spending on Electricity by Fuel and Year ($ million, nominal)



Source: "*Federal Financial Support for Electricity Generation Technologies*" UTEI 2016. Ibid, Pg. 20.

FIGURE 16:

Composition of Support by Fuel and Year



Source: "*Federal Financial Support for Electricity Generation Technologies*" UTEI 2016. Ibid, Pg. 20.

Solar, on the other hand, relies on the investment tax credit that supports generation capacity.

Increased awareness of the effects fossil fuel consumption on our health and the climate impact the utility in various ways. At the federal and state level, subsidies for renewable energy technologies enabled a massive expansion of renewable generation capacity. This coincided with the use of renewable energy through state RPS.[91, 92] While the motivations behind these policies are not purely environmental, a concern for environmental sustainability is clearly influential.

91 Handy, Ryan, "Texas Wind Power Blows Away Old Record" Published December 3, 2016.

92 Woodfin, Dan, "CREZ Transmission Optimization Study Summary", Presented April 15, 2008.

The renewable industry is aided by direct subsidies while the fossil fuel industry is supported by indirect subsidies. In total dollars spent, the federal government devotes comparable funding to the fossil fuel and renewables industry, but renewables receive significantly larger support in the generation of electricity. To keep energy prices low, federal investment in the fossil fuel industry promotes the general production of energy, not electricity or fossil fuels specifically. In practice, this policy is in place to encourage the production of fossil fuels, not necessarily their use in the electricity sector.

For utilities looking toward the future, increased federal funding for renewables is unlikely. The production tax credit and the investment tax credit are secure until their scheduled phase periods in 2020 and 2021 respectively. Fortunately for the solar and wind industry, significant investment has already been made, and renewable energy is increasingly financially viable without federal subsidization. Additionally, a great deal of political power and will in these matters resides at the state and regional level, allowing for more flexible and responsive policy. As a key stakeholder, the utility will need to maximize their participation in these policy discussions to help shape their final forms. Where allowed, they will also need to create incentives of their own, to be used as tools to maximize the utility benefits of DER, instead of simply reacting to DER proliferation as the result of policies not aligned with utility priorities. ■

ANALYSIS: COMPARING NEW BUSINESS MODELS

The utility is transitioning toward less carbon-intensive fuel mixes and higher levels of DER penetration. This change is degrading the utility's ability to earn profits, as the classic COS model is subject to the utility death spiral. These dynamics have given way to new business models that aim to improve the utility's profitability, while expanding and integrating DER. The six models in this comparative analysis include:

1. New York's Reforming the Energy Vision (NY REV)
2. California Proceedings (CA Proceedings)
3. UK's Revenue = Incentives + Innovation + Outputs Model (RIIO)
4. Lawrence Berkeley National Labs Models (LBNL)
5. Rocky Mountain Institute's Electricity Innovation Lab Models (RMI)
6. Transactive Energy Model (TE)

Note: While NY REV, the CA Proceedings, and RIIO have been put into practice, LBNL, RMI, and Transactive Energy are hypothetical or proposed.

These business models make some key assumptions that limit their application in the current electricity generation, transmission, and distribution climate. Notably, they focus on distribution utilities, not bulk power systems. These models are designed to shift a portion of electricity supply from the bulk power system to a distributed supply via increased DER penetration.

Another key assumption made by models is that load projections have low load growth. Under current business models, the electric capacity is directly tied to earnings. Flat load growth therefore results in low revenue under traditional utility business models, presenting an avenue for new models that restructure the utility's means of creating revenue.

The six models analyzed in this report are described below.

CHARACTERISTICS OF NEW BUSINESS MODELS

New York's Reforming the Energy Vision

This state-wide comprehensive energy strategy came to life in the aftermath of hurricane Sandy in 2012. The initiative aims to build a robust electric utility system through DER incorporation, customer engagement, environmental protection, and job creation. Revolving around the Distributed System Platform (DSP), DER suppliers engage in proliferation and monetization of new energy products.[93] In Track One, utilities are DSP providers that focus on collaborative deployment of DER, new system planning, and product design. Track Two reforms utility earning mechanisms through the DSP and reformed rate structures.[94]

Distributed System Implementation Plan (DSIP) guidance "serves as the template for utilities to develop and articulate an integrated approach to planning, investment, and operations."[95] The guidance requires the utility to examine load growth projections and determine responses to high DER penetration. IOUs then submit a joint DSIP with strategies to implement demonstration projects that address DER-related issues and support NY REV guidelines.

Cost of service charges are expected to remain in the NY REV model. These regulatory service charges will help cover fixed costs, and be supplemented by rates and incentives. The model's proposed incentives offset revenue changes from customer-sided DER and allow the utility to maintain a stable level of revenue. The utility is also able to get a profit through an Earnings Adjustment

93 Virginia Lacy, "New Utility Business Models for an Evolving Industry", Presented October 6, 2016.

94 Ibid.

95 State of New York Public Service Commission, *Case 14-M-0101: Distributed System Implementation Plan Guidance* (2015), Pg. 1.

Mechanism (EAM) that is gradually phased out as the utility transitions to a larger amount of DER.

The new rate structure emphasizes locational costs through a new rate formula. Location Marginal Price + Demand (LMP + D) measures the marginal price of electricity and the value of DER resources.[96] Types of demand include "load reduction, frequency regulation, reactive power, line loss avoidance, resilience and locational values as well as values not directly related to delivery service such as installed capacity and emission avoidance."[97] It does not include (1) environmental and public good benefits that are less easily measured, or (2) complete fixed cost recovery for the utility aside from Platform System Revenues (PSR). [98] Because demand is difficult to quantify, this business model risks cost recovery shortfalls as DER saturation increases. It is best used as a transitional cost recovery model.

California Proceedings

Unlike the other models described in this report, there is little attempt in California to craft a unified vision for the future of the utility. Instead, California pursues aggressive policy goals with regulatory action. While this ad-hoc approach has made California a leader in innovative energy policy, it is a source of criticism from utility stakeholders who prefer a more focused dialogue on what model best fits the utility's changing role.[99]

A transformative regulation in California is its Renewable Portfolio Standard (RPS), established in 2002. The program was accelerated by subsequent legislative and executive action. In 2011, Governor Jerry Brown set a goal of 20,000 MW of renewable generation capacity by 2020 composed of both large-scale and distributed generation, including 12,000 MW of new distributed renewable generation.[100] The Clean Energy & Pollution Reduction Act of 2015 mandated that renewable generation compose 50% of total retail sales by 2050.[101]

These policies are in part implemented through the California Public Utilities Commission (CPUC). In 2010, the Assembly directed the CPUC to open proceedings to determine appropriate targets for the utility to procure energy storage systems to trigger an "[energy] market transformation."[102] In 2013, the CPUC passed a mandate requiring the state's three largest investor-owned utilities to add 1,300 MW of energy storage by 2020.[103] Under that plan, utilities are limited to owning no more than half of the storage they incorporate onto their system.

In 2015, the CPUC's Policy and Planning Division analyzed the challenges to the current business model and evaluated three options for future models. Because the utility is already directed to invest in their distribution grids to accommodate two-way flows, their analyses assume a platform-capable grid, if not a platform-style market.

1. The first option is also the most conservative, retaining the basic COS model while exploring ways to allow the utility to collect more revenues on their platform. The utility acts as an all-encompassing platform, retaining responsibility for safety and reliability as well as planning investment and ownership of distributed and utility-scale generation. [104]

2. The second model is more market-based; it is derivative of NY REV, as it uses a "smart integrator" model. Under this model, the utility's role is "to create an interoperable platform from which many market participants can engage."[105]

96 State of New York Public Service Commission, *Case 15-E-0751: Notice Soliciting Comments and Proposals on an Interim Successor to Net Energy Metering and of a Preliminary Conference* (2015), Pg. 2.

97 State of New York Public Service Commission, *NOTICE SOLICITING COMMENTS AND PROPOSALS ON AN INTERIM SUCCESSOR TO NET ENERGY METERING AND OF A PRELIMINARY CONFERENCE* (2015), Pg. 2.

98 State of New York Public Service Commission, *Case 14-M-0101: Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision: Order Establishing the Benefit Cost Analysis Framework* (January 21 2016), Pg. 6

99 Paul Augustine, "The Missing Piece in California's Electric Utility Reforms", Published November 2, 2016.

100 Jerry Brown, "Desert Renewable Energy Conservation Plan Meeting, Sacramento, California", Statement made on October 12, 2011.

101 California Legislature, *Senate Bill 250* (2015).

102 California Legislature, *Assembly Bill 2514* (2009).

103 California Public Utilities Commission, "Agenda 12370: Decision Adopting Energy Storage Procurement Framework and Design Program", Published 2013.

104 Ralff-Douglas et al., Pg. 15.

105 Ibid, Pg. 18.

3. The third model, "Utility as Owner of Poles and Wires," envisions a very limited role for the utility, similar to the telecommunications or natural gas industry. In this model, the utility owns and maintain the grid but do not control operations. [106]

> Unlike Model 1, in which the utility played a gatekeeper function in planning and managing the grid, the utility in Model 2 has the narrower role of facilitating access and competition on the grid. While still responsible for the grid's maintenance, reliability, and safety, the utility would be tasked with creating a level playing field for services on the grid.
>
> It is unclear, but assumed, that the utility can collect revenue in Model 2 through fee for service and performance-based incentives as long as the utility maintains financial neutrality between services using the grid. Though this model has the benefit of a more open market and invites more private capital, it might be challenging for regulators to craft a market that does not discriminate against customers who choose not to participate or are unable to participate in the new market for electricity services. Because the model also relies on high DER penetration and economies of scale, a related challenge is designing a market and pricing services in a way that can encourage DER development in the absence of the legislative mandates used to achieve other policy goals. [107]

In Model 3, by contrast, an Independent Distribution System Operator (IDSO) would control real time operation and planning of the grid, just as an Independent System Operator manages electricity across regional networks. For example, "[an electric utility] would not have the authority to decide that batteries would enhance their distribution grid services."[108] That decision-making capability would lie with the IDSO. With significantly reduced operations and administrative costs, the utility would continue to earn revenue streams from capital investments as well as new income from DER projects. Though this model would provide for the most competitive market, the authors seem unconvinced that it can deliver the environmental benefits California seeks. [109]

United Kingdom's Revenue = Incentives + Innovation + Outputs Model

The United Kingdom (UK) has spent considerable time and effort trying to understand the challenges facing the gas and electricity industries. In early 2009, "Project Discovery" was launched to study energy supply and security in UK for the next 10-15 years. The resulting report identified five key issues:[110]

1. Despite difficult economic conditions, as well as mounting risk and uncertainty, there is still a need for investment.
2. Uncertainty in the future price of carbon might decrease investment in low carbon technology, forcing future generations to bear a great burden of decarbonization costs in the future.
3. Short-term price signals sent due to system stress do not accurately reflect the value to customers, and there are weak incentives for investment to improve peaking capacity.
4. Interdependence with international energy markets exposes the UK to risks of supply security.
5. Higher cost of gas and electricity could result in a rise of consumers that are unable to afford their necessary levels of energy, which affects the competitiveness of industry and business.

The Office of Gas and Electricity Markets (Ofgem) responded with the creation of the "RIIO" Model. RIIO stands for Revenue = Incentives + Innovation + Outputs, which could be referred to as performance-based ratemaking. Some have even gone further and labeled it as a "performance-

106 Ibid, Pg. 21.

107 Ibid, Pg. 18-20.

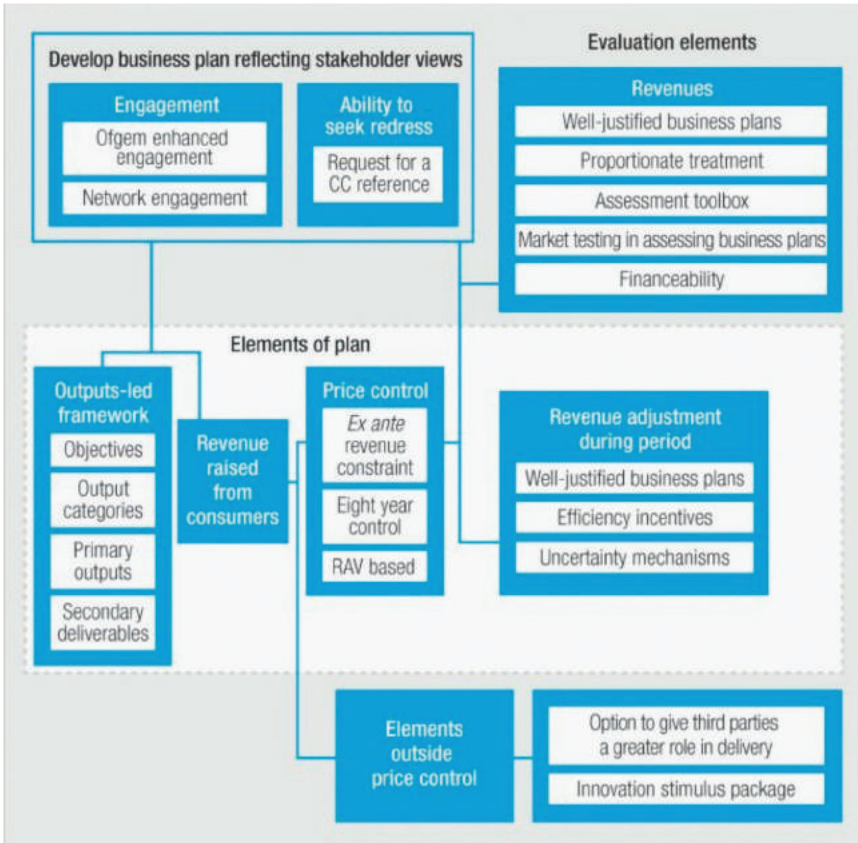
108 Ibid, Pg. 22.

109 Ibid, Pg. 21-23.

110 Ofgem, *Project Discovery Options for Delivering Secure and Sustainable Energy Supplies* (2010), Pg. 1.

FIGURE 17:

Key Elements of the RIIO Model



Source: Ofgem RIIO Implementation Handbook, 2010. Project Discovery Options for Delivering Secure and Sustainable Energy, Pg. 4.

based revenue cap with decoupling."[111] The model is designed to be implemented in all four energy network sectors (gas transmission, electricity transmission, gas distribution, and electricity distribution), but the electricity distribution sector (RIIO-ED1) will be the focus of this paper.

For RIIO-ED1, the 14 distribution energy network operators (DNOs) submit their business plan to Ofgem.[112] The quality of the plan helps determine three sets of financial controls: performance metrics, allowed revenue requirement, and mechanisms for addressing uncertainty.[113] Perhaps the most important and innovative aspect of the RIIO model is its five-pronged focus on consumers, including reliability, customer satisfaction, quicker connections, service incentives, and a focus on social obligations.[114]

The innovation stimulus is an important aspect to the model and has three components:[115]

- Network Innovation Competition (NIC) — for the first two years of ED1, NIC fund for electricity will be £90 million per year
- Network Innovation Allowance (NIA) — funds small-scale innovation projects
- Innovation Rollout Mechanism (IRM) — enables companies to apply for additional funding to rollout a proven innovation

111 Fox-Penner et al., *Great Britain's Latest Innovation in Grid Regulation* (2013), Pg. 1.

112 Ibid.

113 Ibid, Pg. 2.

114 Ofgem, "Price Controls Explained", Published March 2013, Pg. 3-4.

115 "Price Controls Explained", Pg. 4.

Lawrence Berkeley National Laboratory Model

Lawrence Berkeley National Laboratory (LBNL) envisions two distinct futures for the utility industry based on a range of assumptions. First, a significant number of customers will adopt DER due to their attractive cost and performance characteristics, which include energy production, management, and storage.[116] Second, DER will largely be designed for customers and share characteristics of HVAC, electronics, and system management services markets. DER will most easily be integrated into homes and facilities, making it difficult for the utility to procure and own them for financial gain. Additionally, LBNL noted that the development of distributed storage systems to store large quantities of energy economically would be critical to supporting defection from the grid. LBNL specifically looked at a high DER scenario where market penetration ranged from 19-37.5%.[117]

Successful distribution utilities followed two paths: smaller, rural cooperatives and municipal utilities adopt the energy services strategy while large, investor-owned utilities lead the integrating strategy.[118] Small utilities might compete in locations where they added value, such as areas with low customer densities or those with high levels of insolation. They connect with customers through relationship marketing, which conveys that the utility is looking out for their customers' best interests. These utilities also bundle services such as access to community solar, energy-saving water kits, remote appliance control for lights, and even tree trimming.[119]

Investor-owned utilities take the integrating approach and capitalize on their informational and technological advantage. They invest in DER management systems (DERMS) and call on customer-sited DER to help balance supply and demand. Having the advantage of size, utilities could respond to general system peaks as well as site-specific capacity problems. The management systems are expensive but returned significant savings, and investors and customers benefit from lower costs. In both cases, successful distribution utilities knew their markets and appropriately leveraged their size.

These two futures incorporate several key conclusions about the "electricity ecosystem" in 2030:

- The bulk power system is less costly, far cleaner, and increasingly competitive.
- The current network of power plants and transmission lines remains the same and is vital to advancing public policy goals. DER are competitive with energy delivered through the grid, which flattens consumption peaks. The generation fleet shrinks as uneconomical units are retired.
- Distribution system costs have fallen, but the value of services has increased because of new, competitive DER alternatives.
- Distribution utilities still provide essential system services now thought of as: "Connected Capacity" – the maximum energy that a customer can draw through the distribution system at any moment; and "Delivered Energy" – grid energy used on demand by the customer, up to the connected capacity level.
- High adoption of DER drives down cost and is often used to protect against interruptions attributable to extreme weather. This comes at a cost to the utility: a reduced sales volume for connected capacity and delivered energy result in a systemic price squeeze.[120]
- The utility cuts costs and increases the value of being connected to the grid by using customer-owned DER.
- Despite significant revenue erosion from the price squeeze, innovative utilities remain profitable. DER substitutes costly utility infrastructure as well as operational challenges like managing voltage power on feeder lines. Giving customers the option of selling energy back to the grid increases

116 Steve Corneli, et. al., *Electric Industry Structure and Regulatory Responses in a High Distributed Energy Resources Future* (2015), Pg. 13.

117 Ibid, Pg. 51.

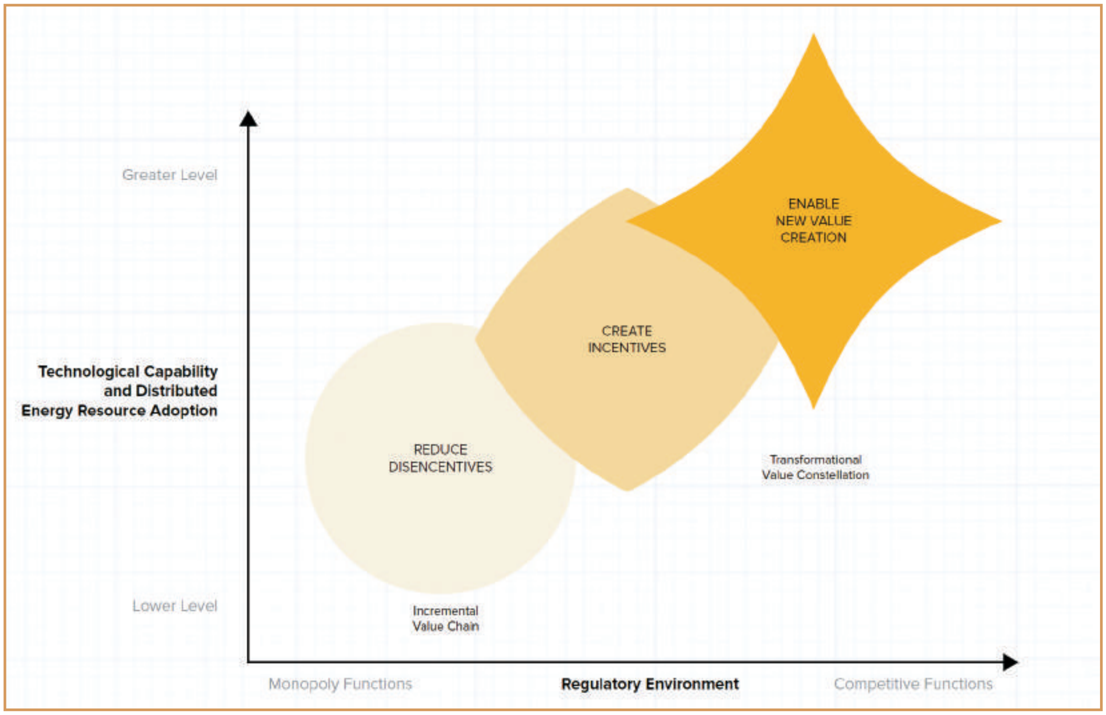
118 Ibid, Pg. 39.

119 Ibid, Pg. 44.

120 Ibid, Pg. 27.

FIGURE 18:

Technological Capability and the Regulatory Environment are the Two Main Factors Influencing New Business Models



Source: Rocky Mountain Institute eLab, New Business Models for the Distribution Edge (2013), Pg. 12.

their desire to remain connected and pay for their share of the costs. Innovative utilities also benefit from virtual integration, relying on smart meters to control information.[121]

- Capital markets increasingly value utilities on new metrics. The Revenue Requirements at Risk (RRAR) refers to the share of the Rate Base invested in assets that could become uneconomic with DER adoption. The System Value to Customer (SVC) refers to the net incremental value to customers for staying connected to the grid. To minimize the RRAR and maximize the SVC, distribution utilities reconfigure themselves as platforms to attract customer and third-party investment in DER.[122]
- Internet companies and other large firms, including major energy companies, rush to supply customers with DER services and cloud-based services like home security, EV charging, transportation, and shopping.[123]
- Investors have a clear preference for full separation of utility DER enterprises from the regulated utility. Adding DER in the rate base isn't economical, and there is value in having spun-off, competitive DER companies that can attract high-risk desiring investors.[124]

Rocky Mountain Institute's Electricity Innovation Lab Models

RMI's Electricity Innovation Lab (eLab) is a collaboration of various electricity generation stakeholders with the goal of developing ways to increase the adoption of DER due to the social benefits provided by distributed resources. Per RMI, the traditional electric utility business model does not properly incentivize DER, and new

121 Ibid, Pg. 29.

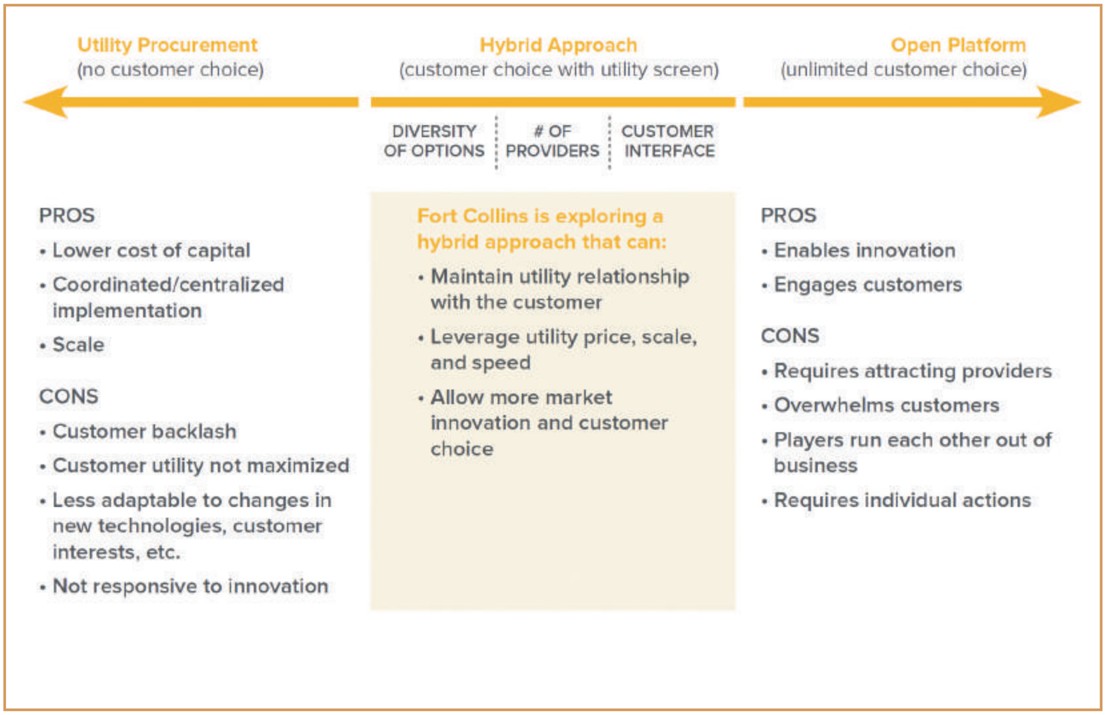
122 Ibid, Pg. 30.

123 Ibid, Pg. 30.

124 Ibid, Pg. 31.

FIGURE 19:

The Integrated Utility Services Program



Source: Rocky Mountain Institute eLab. 2014. Ibid, Pg. 12.

models are needed to allow for DER expansion. The eLab conceptualized three new business models that offer possible ways the utility can incentivize DER while generating revenue through value creation, primarily based on technological capability and the regulatory environment.

While the models all share the common goal of moving the supply of electricity from centralized to distributed resources, each model is unique in its approach. The summaries below are a snapshot of the models described in RMI's 2013 report, "New Business Models for the Distribution Edge."[125]

In the DER Dispatcher model, the utility manages DER expansion and is responsible for creating programs to support development.[126] A peer-reviewed evaluation of alternative system requirement options for electricity generation identifies the areas where DER are the most economic option for generation, and the utility is then required to develop programs that arrange for implementation in these areas. There are several ways these programs can be structured, including issuing requests for proposals (RFPs) for third-party providers, using incentive payments to directly motivate customers to participate, or adding utility-owned and operated DER.

In the DER FinanceCo model, the utility acts as a financier.[127] Whereas the DER Dispatcher model gave the utility oversight, the DER FinanceCo model is much more customer-driven. In this model, the utility provides on-bill financing for customers interested in DER installation and offers a new tariff structure for participating customers similar to Austin Energy's VOST. Participating customers choose from a menu of energy services offered from pre-approved third-party energy service providers. The utility and the energy service providers engage in a cooperative relationship

125 Ibid.

126 Ibid, Pg. 15.

127 Ibid, Pg. 16.

where the utility receives a share of commission from the products and bundles sold by the energy service provider.

The Distribution Network Operator (DNO) model differs from the previous two models in that the utility is split into two entities: one being the physical, distribution wires, and the other being the electricity supplier.[128] In this model, the distribution network is unbundled and the electricity supply is shifted to DER. The wires part of the utility (or DNO) continues to operate as a regulated monopoly, but now is required to encourage DER development, e.g. offering incentive payments. Subjecting the DNO to performance-based ratemaking would motivate the utility to keep distribution costs low. In turn, this prompts the DNO to offer price mechanisms to customers that would make DER investment more attainable. The DNO in this model functions similarly to an Independent System Operator (ISO).

RMI worked with Fort Collins Utilities to initiate its Integrated Utility Services (IUS) Program.[129] The IUS Program aims to capture the social benefits that come with a more open grid and increased DER while maintaining the utility-customer relationship. The IUS Program is a hybrid between the traditional utility business model and an open platform model. In the IUS program, Fort Collins Utilities offers a complete package of energy-efficiency services to customers using on-bill financing to help customers pay for their services.

The program is intended to benefit both the customer and the utility. The program's design is simple and straightforward, allowing for easy customer participation. By offering energy service bundles and on-bill financing, customers are not required to thoroughly research numerous menu options or make complex financial arrangements that might dissuade potential participants. The utility has the potential to take advantage of many additional benefits from the IUS Program. The utility can develop and offer pricier, premium packages for additional revenue and, through performance-based ratemaking, can capture incentive shares.

128 Ibid, Pg. 21.

129 Rocky Mountain Institute eLab, *Integrated Utility Services: A New Business Model for Fort Collins* (2014), Pg. 6.

Transactive Energy Model

Transactive Energy (TE) imagines the ideal grid as one that could incorporate the benefits of network effects. Many customers already share an assortment of good and services through applications like Uber and Airbnb. In the TE model, traditional transmission and distribution systems can also capitalize on the sharing economy by trading electricity through a marketplace based on the grid.

The TE model relies on a high penetration of communication technologies. Market forces for future and current transactions determine investment planning and location of DER deployment coordinated by IDSOs. Energy Boxes, the software for energy management systems, provide autonomous, real-time feedback at every end usage point of the grid. Customers can choose when to buy and sell electricity at a time most beneficial for them. These devices can make decisions on behalf of the consumer by learning energy patterns, removing a need for a centralized entity to control the execution of bids.

Multiple pilot projects around the world have attempted to implement the TE model at different scales. In the Netherlands, Power Matching City created an integrated smart grid of 25 houses in the City of Groningen connected to small renewable energy generators, smart appliances, electric vehicles, and smart meters. It uses a market platform software system to make real time market decision in five-minute intervals to balance supply and demand. The second stage incorporates 40 households and further develops new models.[130] In the U.S., a 5-year transactive control pilot program is testing the TE model across eleven utilities.

COMPARATIVE ANALYSIS

The six business models analyzed in this paper share some common themes. Though each model is tailored to specific energy mixes and customer loads, they each work to incorporate flexibility into their customer service model. Additionally, they all move away from the cost of service model towards a model that integrates DER. Though the

130 Battelle Memorial Institute, *Pacific Northwest Smart Grid Demonstration Project* (2015), Pg. 2.1.

models generally contain some level of fixed cost recovery to help keep the utility solvent during this transition. Because utilities have a range of energy mixes and customer bases, no one business model can (or should) be universally applied.

Though intended as permanent solutions, our analysis shows that none of the models continue to function in a high DER penetration scenario. As shown in ***Table 8*** below, when evaluated against the California Standard Benefit-Cost tests, all models fail to achieve benefits for the utility as DER penetration increases. Benefits are maintained for DER participants and society, even at high penetration levels, but non-DER ratepayer impacts are uncertain.

TABLE 8:

California Standards Tests Table (low load growth scenario)

	Low DER	Transition to High DER	High DER Penetration
DER Participant	✓	✓	✓
Ratepayer Impact	?	?	?
Societal	✓	✓	✓
Utility	✓	?	✗

We developed a total of nine questions with which to interrogate each business model in order to evaluate their future viability while maintaining value for all participants and society as a whole. These questions were selected to reflect driving characteristics of utility business models; they are intended to develop a framework for how stakeholders might evaluate potential future business models, including economic, regulatory, and technological impacts.

Is the model moving toward performance-based ratemaking?

NY REV: Although a utility's fixed costs are recovered through a combination of rates and a COS charge, compensation is also based on earnings adjustment mechanisms (EAMs) and a 5-year rate plan implementing earnings sharing mechanisms (ESMs) in the form of clawbacks.

CA Proceedings: CPUC discusses three different models, including one that relies on COS and one that increases use of performance incentives.

RIIO: Combining an 8-year rate plan (MRP) with a novel set of performance incentive mechanisms (PIMs), capital and operating expenditures become total expenditures (TOTEX). Utilities earn returns on part of the TOTEX, which reduces the incentive to invest in large-scale capital projects.

LBNL: The SVC to RRAR is an innovative approach that promotes enhanced performance over capital investment, which optimizes both value for the customers and revenue for the utility. The model also includes some cost of service regulation for recovery of capital and operating costs.

TABLE 9:

Comparative Analysis of New Business Models

Evaluation metric	Business Model					
	NY REV	CA	RIIO	LBNL	RMI	TE
COS to PBR Transition	●	◑	●	●	●	◑
DER Encouragment	●	◑	●	●	●	●
DER as Cost Reduction Tool	◑	◑	○	◑	◑	○
Customer Engagement	●	◑	●	●	○	◑
Platform Model	●	◑	○	●	◑	●
Fixed Cost Recovery	COS + Fixed Change	COS + Min. Bill	Policy + RAV	N/A	NUC + Tariff	COS + Access Fees
Profit-Making	PER+MBR	PER+MBR	PBR	MBR	PER+MBR	MBR
Role of DSO	None	Operation	Price Settings + Regs	Operation	Operation	Operation
ESU or SIM	SIM	SIM	SIM	Both	Both	SIM

● YES ◑ SOMEWHAT ○ NO

RMI: Performance-based ratemaking is suggested for all three models, though there is no mention of dropping COS regulation. In RMI, COS is essential for fixed cost recovery while performance measures incentivize DER. RMI particularly advocates using performance-based incentives to motivate increased DER by rewarding energy savings.

Transactive Energy: Adherence to COS for cost recovery is combined with performance measures and benchmarks for transmission and distribution utility models.[131]

Does the model encourage DER adoption?

NY REV: The model's Distributed System Implementation Plans (DSIPs)[132] require the IOU to submit individual and joint plans that look at different aspects of DER with a focus on problem-solving through demonstration projects like the Brooklyn/Queens Demand Management (BQDM) Program.

CA Proceedings: Draft proposals to the CPUC encourage the utility to procure DER in traditionally underserviced areas.[133]

RIIO: In the model's "Network Innovation Allowance," small scale projects including DER are part of allowed revenues.[134] Additional performance measures include DER connection and prosumer satisfaction.[135]

LBNL: The model encourages the utility to participate in further DER development via two non-exclusive strategies.[136] (1) Competition between utilities and DER providers to connect with customers with pre-existing energy generation capacity. (2) Utility control of distribution assets that connects electricity retailers with customers and DER providers.

RMI: Performance incentives will tie revenue to DER-favorable policies. Revenue streams will form through technological innovation. The DER FinanceCo model focuses on third parties offering products and services to customers, while the DNO model encourages using DER to reduce operational costs associated with distribution.[137]

Transactive Energy: Reducing regulatory barriers allows DER stakeholders to be fairly compensated by market forces. Dispatch of DER at specific locations optimizes grid functionality. DSO will assume risks otherwise borne by the utility.[138]

Are DER used to reduce costs for the utility?

NY REV: ConEd's BQDM project reduces utility costs by implementing a demand reduction program coupled with customer DER development.[139] This individual example illustrates DER can be used to reduce costs using NY REV, but there were not sufficient examples to determine the magnitude of savings that DER could provide.

CA Proceedings: Similar to NY REV, CA Proceedings provided an example in which DER reduced costs for IOUs. The cost reduction was due to a decrease in load growth, eliminating the need for line transmission improvements and transformer replacements.[140] However, this is a single example and is insufficient to determine the magnitude of cost reductions from DER.

RIIO: There is no evidence to show the RIIO model incentivizes the utility to reduce their costs using DER.

LBNL: DER deployed strategically can help the utility offset capital outlays. With respect to

131 Jon Wellinghoff et al., *The 51st State of Welhuton: Market Structures for a Smarter, More Efficient Grid. 51st State Initiative* (2015), Pg. 15.

132 State of New York Public Service Commission, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Staff Proposal Distributed System Implementation Plan Guidance* (2015), Pg. 6.

133 California Public Utilities Commission, *Assigned Commissioner's Ruling Introducing a Draft Regulatory Incentives Proposal for Discussion and Comment* (2014), Pg. 5.

134 Ofgem, *Price Controls Explained* (2013), Pg. 4.

135 Ofgem, *Strategy Decision for the RIIO-ED1 Electricity Distribution Price Control-Overview* (2013), Pg. 27.

136 Steve Corneli et al., *Electric Industry Structure and Regulatory Responses in a High Distributed Energy Resources Future* (2015), Pg. 39.

137 Rocky Mountain Institute, *New Business Models for the Distribution Edge* (2013), Pg. 14, 16, 21.

138 Wellinghoff et al., Pg. 7.

139 State of New York Public Service Commission, *Con Edison's DSIP presents its self-assessment and five-year view of the integration of Distributed Energy Resources into Planning, Operations, and Administration* (2016), Pg. 11.

140 Julia Pyper, "Californians Just Saved $192 Million Thanks to Efficiency and Rooftop Solar", May 31, 2016.

the LBNL's Energy Integrator Model, utilities reduce costs through investing in customer-sited management systems to integrate DER where they could balance supply and demand. In this way, the utility can respond to system peaks as well as locational problems with site-specific capacity limits. The capital-intensive investment ultimately results in substantial savings.[141]

RMI: DER benefits the utility as a tool to meet demand response by extending the service life of existing infrastructure.

Transactive Energy: An impartial grid manager lessens the burden of cost recovery by undertaking traditional utility operational responsibilities. Subsequent cost savings outweigh the importance of DER for cost recovery.[142]

Does the model engage the customer?

NY REV: The Distributed System Implementation Plan lays out stakeholder engagement with low and middle-income customers through advisory boards and engagement conferences.[143] ConEd discusses its own Low Income Program Implementation Plan that emphasizes targeted outreach and education.[144]

CA Proceedings: Through smart home products and time of use (TOU) rates, CPUC encourages innovation on the consumer side while being careful not to disadvantage low-income customers who are less able to participate in alternative energy production markets.[145]

RIIO: Ofgem encourages engagement goals in which stakeholders are familiarized with policy developments and procedures by promoting collaborative contributions through price control reviews.[146] Examples include: adoption of independently conducted assessments of stakeholder engagement and customer service;[147] The "worst-served customer" fund for network improvements in remote locations; Priority Services Register service for elderly, disabled, ill, or otherwise vulnerable customers.[148]

LBNL: The Energy Services Utility caters to consumers by offering a menu of energy packages to choose from. Though low-income customers are not addressed specifically, the report references potential benefits to isolated areas where customers are often underserved.[149]

RMI: As the models are still conceptual, there is not a detailed low-income customer or customer engagement strategy.[150]

Transactive Energy: Prosumers are fully engaged, but non-participating and low income customers could be negatively affected.[151]

Does the model utilize a distribution platform system?

NY REV: A core principle of the NY REV is the creation of a Distribution System Platform Provider (DSPP).

CA Proceedings: California has not committed outright to a platform model, but CPUC directed utilities to upgrade their systems to "accommodate two-way flows of energy and energy services, enable customer choice, and animate opportunities for DER to realize benefits through the provision of grid services."[152]

RIIO: The platform model is not used.

LBNL: The Integrating Utility Model requires the utility to act as a platform for managing DERMS.[153]

RMI: The DER Dispatcher Model is similar to a platform model in that network use charges can be implemented.

Transactive Energy: With reliance on a peer-to-peer network for transactions, transmission and distribution grids serve as platforms.[154]

141 Steve Corneli et al., Pg. 43-46.

142 Wellinghoff et al., Pg. 7.

143 New York Public Utilities Commission, *Supplemental Distributed System Implementation Plan* (2016), Pg. 5.

144 ConEd, *Low Income Program Implementation Plan* (2016), Pg. 2.

145 Kristin Ralff-Douglas et al., *Electric Utility Business and Regulatory Model* (2015), Pg. 9.

146 Ofgem, Pg. 16.

147 Ofgem, *Price Controls Explained* (2013), Pg. 3.

148 Ofgem, "Consumers, Household Gas and Electricity Guide", 2017.

149 Corneli et al., Pg. 45.

150 Rocky Mountain Institute, *New Business Models for the Distribution Edge* (2013), Pg. 8.

151 Wellinghoff et al., Pg. 19-20.

152 Ralff-Douglas et al., Pg. 9.

153 Corneli et al., Pg. 46.

154 Wellinghoff et al., Pg. 1.

How does the utility recover fixed costs?

NY REV: NY REV recovers fixed costs through a combination of rates and fixed charges.

CA Proceedings: The California Proceedings recover fixed costs through cost of service regulation with an allowed minimum bill.[155]

RIIO: RIIO proposes "a capitalization policy based on equalizing incentives and more closely aligned with the actual split between operating and capital expenditure" and adding a fixed proportion of costs to the regulatory asset value (RAV).[156]

LBNL: LBNL does not specifically identify how fixed costs will be recovered.

RMI: The DER Dispatcher model unbundles energy-related charges and network charges since DER provides the energy supply.157 A network use charge could be put in place to recover fixed distribution-related costs. In the DER FinanceCo model, the utility would recover fixed charges through a tariff charge for participating customers.[158]

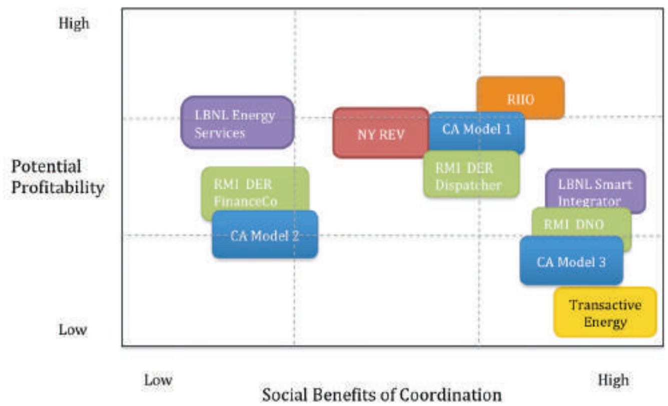
Transactive Energy: The utility uses a cost of service model in which sunk costs are recovered through access fees for third party providers, which depend on the amount of line capacity they expect to occupy.[159]

How does the utility make a profit?

In analyzing the high DER future of electric utility business models, LBNL created the Potential Profitability and Social Benefits of Coordination (PPSB) framework demonstrated through a series of graphs comparing social benefits of coordination to potential profitability for different industries as well as aspects of the electric utility industry.[160] Using the LBNL framework, the figure below compares each utility business model studied for this report.

FIGURE 20

PPSB Distribution of Business Models



Moving from a birds-eye view of rate plans to more granular details, the following table addresses profit making characteristics for long term market sustainability. Given the larger trend of government services privatization, new models must be financially compatible with today's rapidly changing utility and energy market. Utilities that do not incorporate alternative energy capabilities will result in decreased electricity sales and revenue due to the confluence of decreasing load growth, growing DER adoption, and increasing energy efficiency. Identification of specific revenue recovery mechanisms enables policy-makers to best understand the value of each model with respect to their constituent markets.

Performance Based Ratemaking (PBR) and Market Based Revenues (MBR) are revenue-making mechanisms. In PBR, revenue is dependent on the practicality of customer performance targets,[161] and overly ambitious targets can lead to revenue shortfalls. Consequently, performance standards should be carefully considered. On the other hand, MBR is generated from the sale of DER products and services to customers. The utility or retailers sell products and services to customers. The utility business model described by LBNL uses a

155 Public Utilities Commission of the State of California, *Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations* (2012), Pg. 189-231.

156 Ofgem, *Strategy Decision for the RIIO-ED1 Electricity Distribution Price Control-Overview* (2013), Pg. 42.

157 Rocky Mountain Institute, *New Business Models for the Distribution Edge* (2013). Pg. 15.

158 Ibid., Pg. 16.

159 Wellinghoff et al., Pg. 6.

160 Corneli et al., Pg. 9.

161 Corneli et al., Pg. 34.

TABLE 10:

Utility Profit Models

Structure		Business Model					
		NY REV	CA	RiiO	LBNL	RMI	TE
COS		●	●	●	●	●	●
PBR	Performance Incentives	●	●	●	○	●	●
	Multiyear Rate Plans	●	○	●	○	○	○
	Earnings Sharing Mechanisms	●	○	○	○	●	○
MBR		●	●	●	●	●	●

● YES ◐ SOMEWHAT ○ NO

market-based approach for revenue generation, such as in the Energy Services Utility model.[162] Transactive Energy's platform-style marketplace also relies on MBR for profit potential.[163]

NY REV offers a combination of performance-based incentives, as well as MBR. PSR includes platform access fees, platform transaction fees, data analysis, co-branding, scheduling services, advertising, energy service financing, and advisory services.[164] In the long run, PSR could become the main source of revenue for the utility under the NY REV model. Currently, an additional measure for revenue generation exists in the form of EAM (a form of PBR), where the utility profits from peak reduction, energy efficiency, and customer engagement.[165]

The business models described by RMI and the CPUC indicate multiple potential revenue sources. RMI and CPUC advocate using performance incentives to motivate DER saturation by rewarding energy savings. RMI's DER Dispatcher and DER FinanceCo models follow a market-based approach for revenue through direct offering of DER products and services or commission from third-parties.

PBR and MBR comprise the two main profit-making mechanisms. While RIIO and LBNL focus on single profit-earning mechanisms, most models elect to support multiple revenue streams. Since the two methods can complement each other in the goal of transitioning to a distributed energy supply, a successful business model will likely include both measures. As demonstrated by NY REV, PBR can generate revenue until MBR becomes profitable.

Opportunities for MBR are growing. The expansion of electric vehicles and eventual market maturation of grid storage solutions have large implications for models that promote DER. EV saturation will generate significant revenue from resulting load increases.[166] Additionally, MBR will likely see increases from auxiliary product saturation including batteries and charging stations.

What is the role of the distribution system operator?

NY REV: Role of DSO is expanded to become a DSPP, operating the distribution grid and trading platform.

CA Proceedings: IDSO will mirror ISO/RTO functions and oversee moment-to-moment

162 Corneli et al., Pg. 43.

163 The GridWise Architecture Council, *GridWise Transactive Energy Framework Version 1.0,* Pg. 24.

164 The GridWise Architecture Council, (2015) Pg. 41.

165 Ibid, Pg. 13.

166 Chris Nelder, James Newcomb, and Garrett Fitzgerald, *"Electric Vehicles as Distributed Energy Resources",* (2016).

end use operations of the distribution system in addition to facilitating transactions. Also, the utility owns capital investments in DER and retain returns on investment income.[167]

RIIO: U.K. Distributed Network Operators (DNOs) function much like DSOs in the U.S. Responsibilities include developing price controls and maintaining reliability. Fourteen DNOs oversee operations, and each must submit a business plan to Ofgem for approval, which is then authorized by the Gas and Electric Markets Authority (GEMA) and placed under their jurisdiction. Ofgem plays a role similar to both the Public Utilities Commission (PUC) and Federal Electricity Regulatory Commission (FERC) in the U.S.

LBNL: The utility still serves as distribution system operators in the Energy Systems Model, and in the Smart Integrator model the utility owns DERMS and do not rely on an IDSO.[168]

RMI: The DNO model, which is an independent distribution system operator model, focuses on DER incentives through price signals while minimizing distribution network costs. In this framework, distribution utilities maintain ownership over physical infrastructure and earn revenue through their capital investments. RMI suggests rewarding distribution utilities that facilitate lower distribution capital investment and costs through regulatory incentives such as shared savings. These incentives could allow cost savings and investment in DER that offset infrastructure costs while generating a return on investment for the utility.[169]

Transactive Energy: IDSO is responsible for grid operational capacity and transaction facilitation. The utility generates revenue from production assets.[170]

167 Zarfar, Marzia and Kristin Ralff-Douglas, Electric Utility Business and Regulatory Models (2015).

168 Corneli et al., Pg. 46.

169 RMI, "New Business Models for the Distribution Edge" (2013).

170 Wellinghoff et al., Pg. 7.

Does the model utilize an Energy Services Utility or Smart Integrator?

NY REV: NY REV is primarily a Smart Integrator due to the reliance on platforms to allow customers to produce and sell their own electricity while providing a stable source of revenue for the utility.[171]

CA Proceedings: The California proceedings largely describe a Smart Integrator model. Two of the models predicted by CPUC contain interoperable platforms on which participants could engage.

RIIO: RIIO is also a Smart Integrator because it relies on a smart grid to resolve constraints on the network rather than investing in additional generation and allows the DNO more flexibility in trying to plan for long-term demand.

LBNL: The LBNL model uses both the Energy Services model and the Smart Integrator model as the two most likely futures for the utility in a high DER environment. In this environment, small or rural utilities offer additional services to customers and large investor owned utilities utilize an integrated network to attract capital.[172]

RMI: The DER Dispatcher model is similar to a Smart Integrator model in that the utility manages DER and the utility commits to investing in DER. The DER FinanceCo model is closer to an Energy Services model, in which the utility offers products and services directly or through a third-party.

Transactive Energy: With an emphasis on two-way energy transfers, the Transactive Energy model is a Smart Integrator model that allows independent market participants to buy and sell energy in real time.[173]

171 State of New York Public Service Commission, "Distributed System Implementation Plan Guidance" (2015), Case 14-M-0101.

172 Corneli et al., Pg. 39.

173 Wellinghoff et al., Pg. 4.

CONCLUSIONS

The conclusions of this report are listed below. They include findings and recommendations for decision-makers related to economic, regulatory, and technological changes in the electricity sector. An overarching theme across several conclusions is that the diversity of service area conditions will result in a range of narrowly tailored solutions, as opposed to a single new business model.

ECONOMIC

These new business models will struggle in a low load growth, high DER scenario.

Though the new business models discussed in this report might work well in a low penetration DER scenario, they will not continue to work in a low load growth, high DER environment. Declining or low load growth greatly impacts all the models in how they recover their fixed costs and make a profit. Moreover, increasing DER penetration generally reduces customer's bills and usage, without significantly reducing costs to the utility. The potential for low load growth to be coupled with high DER penetration could prove to be a killer combination for the new models.

Accommodate uneven fiscal impacts by understanding utility and market characteristics.

In order to fiscally accommodate DER, the utility must identify 1) market conditions and DER deployment scenarios for their specific utility, 2) relevant societal benefits and regulatory incentives (as well as where the utility is positioned along the LBNL adoption curve, as shown in ***Figure 10***), and 3) the types of DER being adopted within the utility and the effects of those DER on the utility (e.g. peak shaving vs. peak shifting, PV vs. diesel generators, etc.). This variation occurs for several reasons, including climate, the cost of electricity provided by the utility, customers' values, and technology, and it can have a large impact on how a utility must adjust to DER.

The platform business model has only limited applicability to the electric utility industry.

In the telecommunications industry, the platform model has revolutionized the modern economy, but the grid and utility have important distinctions and limitations that raise questions about the platforms applicability to the grid, especially in a high DER scenario. Because of the difficulties associated with transporting electricity, the value of the DER decreases significantly with added distance between the buyer and seller, unlike the telecommunications industry. New products and services developed for the platform that generate revenue for telecommunications firms do not generate revenue for the utility. In fact, energy management systems like NEST thermostats detract from utility revenues. The customer growth experienced with typical models does not apply to the utility because the utility is already required to serve all customers in their designated area. Legally, the utility can only charge an interconnection fee while a typical platform business would charge a premium for access to a higher value grid. Lastly, the utility will not see as many positive network effects because growth on one side of the network (e.g. DER) does not lead to growth on the other side of the network (e.g. utility generators). For all of these reasons, the platform model will likely have limited applicability to the electric utility industry in a high DER scenario and could result in minimal platform system revenues.

These new business models work best as transitional models.

While each of the models examined shows potential during the transition period, none of them are viable (in their current form) for long term success in a high DER/low load growth environment. Each of the models provide short term compensations to the utility for stated goals like incentivizing DER, and investment deferment, but once those "low-hanging fruit" opportunities are actioned, sales of electricity decline. Utilities in these models succeed themselves into bankruptcy. The models assessed here lend themselves best to a transitional role, getting us to diverse, efficient, high DER environment, but requiring a new model (or reversion to a non-profit muni/co-op model) once that transition is complete.

Some electric utilities might not survive the transition (in their current form) to high penetration of DER.

For a number of reasons, some utilities might not survive the transition to high penetration of DER. Revenue will be reduced faster than cost savings and new revenues can accrue. A number of the models rely on cost reduction mechanisms such as reduced capital/operational spending and optimizing the grid; however, these cost reductions will mainly impact future spending and will not come to fruition in time for the utility to offset their current capital and operating expenditures. Similarly, new revenues such as electric vehicle loads, rental fees, and transaction fees will take time to develop as established and reliable sources of income and therefore will not be able to offset the utility's current needs. Stranded costs might not be recoverable as debt service for capital investments already made will still need to be paid. Furthermore, grid costs will shift to customers not able to take full advantage of DER, potentially causing the utility death spiral.

Regulators might also not allow full recovery of fixed costs due to impact on low-income customers and impact on DER deployment. Furthermore, the utility might not have the resources or the competitive edge to out-compete existing companies that already specialize in providing new products and technologies, especially considering the bureaucratic processes many utilities must follow. Finally, regulators might not allow the utility to compete in the DER markets in the same way that deregulated utilities cannot generate electricity.

REGULATORY

These new business models will benefit participating customers and society at large.

In general, the new business models will benefit participating customers by reducing electricity bills, helping the utility with cost-saving, and improving society by using cleaner energy resources. Additionally, the models develop more access-providing options and incentives to customers, encouraging more participants to engage in the marketplace and accelerating the deployment of behind-the-meter DER.

None of these models propose a complete move away from traditional cost of service regulation.

All the models propose the importance of moving away from COS regulation and towards PBR, and therefore currently include some PBR elements. However, none of the models propose regulation that completely moves away from COS. At the very least, COS regulation is used for recovering capital and operational costs regardless of how the utility functions or what services it delivers, since as noted, the different models operate differently and include different investments. This point is particularly true in an environment where the newer proposed market-based services are still in development and perceived by the utility as risky. However, COS regulation under the new models is adapting to accommodate a high-DER future. For instance, lumping the capital expenditures and operating expenditures under the RIIO model, although still counts as allowing the utility revenue that match their costs, does a better job at cutting costs in general. Moreover, future utility business plans are forming a basis for allowable revenues, meaning the regulator can allow a higher rate of return to DER investments. In short, PBR implemented under the new proposed models is a refined PBR approach that creates **more** financial incentives based on value and performance and **less** based on recovery of costs.

A fully regulated model might be the best option for distribution utilities.

The profit potential for distribution utilities in a high DER scenario might be low. The best alternative for a private sector distribution company might be a fully regulated utility, based on a cost of service regulation model. As utilities approach high-DER scenarios, additional installation becomes increasingly less valuable to society overall and can even result in net costs to the utility. Different models propose moving toward revenue sources like PBR, platform access fees, transaction fees, and more active participation in consumer markets for new energy technologies and services like EVs and smart appliances. If these markets prove less robust than hoped, however, and especially if the utility is not allowed to own DER, the profit potential for a distribution utility in a high-DER scenario might be very low. Coupled with the challenge of designing performance metrics that are both appropriate and attainable, a distribution utility might not be able to rely on the predictable profits many have become accustomed to. In such a scenario, the best alternative for a private sector distribution company might be a transition to a fully regulated utility operating under the relative stability of a cost of service model. This model will still face the problem of recovering fixed costs in the face of decreasing volume of sales. The COS model will have to address this with a combination of rate structures that capture fixed costs from DER customers connected to the grid, and fixed charges and/or access fees for all customers.

The IDSO might be the preferable operator system. Such an operator might be a non-profit or government entity.

The utility currently lacks the incentive and capability to deploy and dispatch DER to its projected potential.[174] Capitalizing on a high penetration of DER requires coordinating the deployment of specific technologies in optimal, market driven locations. More than one analysis of the future electricity landscape identifies a third-party as an effective and mutually beneficial grid management strategy. For example, TE model proposes removing the responsibility of day-to-day grid management from the utility, including the burden of maintaining 100% reliable service, and transferring it to an impartial, clearinghouse-type entity much like an ISO/RTO for the distribution grid. The RMI model as well as the California proceedings also propose an IDSO. An IDSO might supervise network planning by recommending investments to regulators and providing objective analysis on rate design. It would also maintain the safety of the distribution grid while providing open and fair access to the grid and its information.

174 J Wellinghoff,. et. al. Pg. 7

Stable policies and pricing might reduce risks in investing in DER. As TE develops, this entity could be absorbed into a regional entity like the ISOs.

TECHNOLOGICAL

Accommodate uneven physical impacts by using software to understand structural characteristics.

The utility and regulators should identify the most beneficial places to incentivize DER. They must understand the physical characteristics of their grid. The utility should use these characteristics as well as increased data communication within the distribution grid to inform where and how to incentivize DER. Section 5, Uneven Penetration Impacts, provides a detailed list of physical considerations. NARUC recommends technologies like Advanced Distribution Management System (ADMS)[175] and Distributed Energy Resource Systems (DERMS)[176] for data processing, DER forecasting, and analytics.

Once a saturation point is reached, additional DER will have limited value to the overall system.

The most significant value of DER to the system is in energy contribution, demand decreases and shifts, displacement of carbon-intensive fuels, capacity additions, and voltage support. These values are most beneficial in the early stages of adoption, while penetration levels are relatively low. At this point, additional DER might be used to defer utility infrastructure investments, alleviate peak load issues and transmission congestion, or to provide ancillary services. The DER owner sees their energy bill go down and perhaps even sells surplus electricity or services. Other grid participants will be enjoying system benefits and reduced environmental impacts without significant impact on their utility bill. At a certain saturation point of additional DER, while still beneficial to the owner (participant customer), will have little value to the system and results in an overall cost to the utility and other customers (non-participating ratepayers).

175 Department of Energy, *Insights into Advanced Distribution Management Systems*, (2015).

176 Distributed Energy Resources Rate Design and Compensation. Pg. 62

Physical limitations of peer-to-peer transactions will ultimately hinder growth in distribution system markets, and fiscal limitations will affect distribution systems.

Factors both natural (i.e. weather, and distance between homes) and logistical (i.e. transmitter capacity, and limited storage) will prevent the long-term growth of a purely peer-to-peer market, in which consumers rely on each other for their energy needs. It may however be possible to operate a hybrid, with some form of utility, as the platform operator, buffering and strengthening the overall peer-to-peer marketplace by ensuring access to additional centrally generated electricity.

Distribution system markets are characterized by multiple energy sellers transacting through a third-party vendor. Regional service providers and ISOs traditionally serve as the third-party role in deregulated wholesale marketplaces, but classic utilities can serve as the local level regulator. Instead of solely providing electricity, utility providers can also charge varying platform services based on demand level and type of seller, adding a revenue stream to counteract lost electricity sales revenue.

The successful integration of DER onto the distribution grid requires the consideration of both physical and fiscal impacts in conjunction with one another. Nationwide, the variation in DER growth rate, climate, utility structure, and physical characteristics is determined by geographical location and other factors. Identifying these characteristics through data collection technologies will better formulate benefit-cost analysis, rate structure, and types of DER to incentivize according to location. ■

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