Evolving Grid Services, Products, and Market Opportunities for Regulated Electric Utilities

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Acronyms and Abbreviations

AMI	advanced metering infrastructure
ARC	aggregator of retail customers
CCA	community choice aggregation
C&I	commercial and industrial
DC	direct current
DER	distributed energy resource
DG	distributed generation
DOE	Department of Energy
DR	demand response
DSM	demand side management
EE	energy efficiency
ESCO	energy service company
EV	electric vehicle
FERC	Federal Energy Regulatory Commission
IT	information technology
IOU	investor owned utility
kW	kilowatt
kWh	kilowatt-hour
NERC	North American Electric Reliability Corporation
NEM	net energy metering
NWA	non-wires alternative
NYISO	New York Independent System Operator
PURPA	Public Utilities Regulatory Policy Act
PV	photovoltaic
TBR	time-based rates
T&D	transmission and distribution
TOU	time-of-use
VIU	vertically integrated utility

Executive Summary

The electric industry is currently undergoing substantial evolution and expansion. Recent technological advancements, as well as changing customer demands, are expanding the number and type of electric utility grid services and product offerings to end-use customers. Furthermore, these forces, as well as societal and economic shifts, are presenting regulated electric utilities with new market opportunities (Cross-Call et al., 2018). Even the definition of the regulated electric utility's customer is evolving by expanding beyond the traditional end-user of electricity into third-party businesses engaging with the utility in order to more successfully sell their own services and products.

This report focuses on the more recent changes and evolutions in grid services, products, and market opportunities regulated electric utilities are offering to their customers, both traditional end-users of electricity as well as third-party party businesses looking to sell their own services and products. As the title of the report suggests, the focus is primarily on "evolution" in electric utility grid services, products, and market opportunities. "Evolution" is defined as the development of a new or different way in which: a) customers receive and/or pay for electric utility services and products; or b) electric utilities support broader market development opportunities, which themselves may result in utility grid service or product offerings. The report presents an analytical approach to identify current examples and categorize them along with key features. The report also links evolutions to the perspectives among regulators, policymakers, utilities, and other stakeholders driving and opposing these evolutions (i.e., "tailwinds" and "headwinds").

Data Sources

In order to identify and understand the drivers for evolution in utility grid services, products, and market opportunities, the report relies on a representative database of over 50 recent regulatory filings by electric utilities and major legislation pertaining to electric utilities. Data collection efforts focused on activities promulgated by or affecting regulated investor-owned electric utilities[1] through the review of public filings in state utility regulatory proceedings, statutes from legislative sessions and utility reports, websites, and presentations to better understand the specifics of the changes being proposed or instituted.

Organizational Framework

The report utilizes a framework for categorizing the recent proposals in the database and characterizes the main pathways of evolution in regulated electric utility grid services, products, and market opportunities. The purpose of the framework in this report is two-fold: (1) to capture and categorize many possible evolutions and (2) to organize evolutions for the purpose of comparing and discussing tailwinds and headwinds.

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[1] In some cases, municipal and cooperative utilities have made evolutions similar to their regulated investor owned utility (IOU) counterparts. However, this report is focused on recent efforts by IOUs.

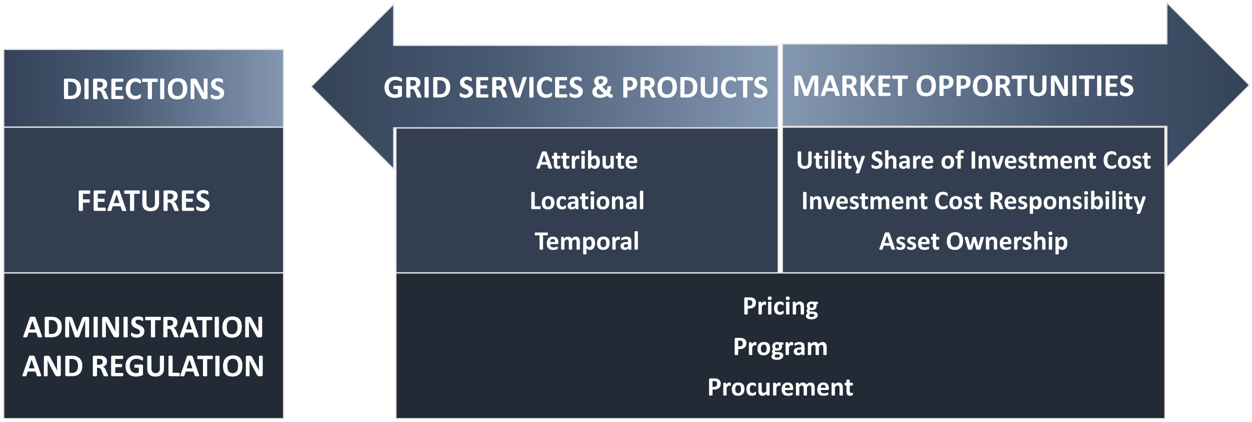

Figure ES - 1. Framework Categorizing Evolutions in Grid Services, Products, and Market Opportunities

As shown in Figure 1, the framework begins by describing two distinct **directions** in which evolutions are trending: 1) grid services and products; and 2) market opportunities. The second dimension of the framework describes **features** of evolutions in electric utility services, products, and market opportunities along six continuums, of which the first three continuums (attribute, locational, and temporal) apply exclusively to grid services and products, while the last three continuums (utility share of investment cost, investment cost responsibility, and asset ownership) apply only to market opportunities. The third, and final, dimension of the framework, **administration and regulation**, characterizes the way in which electric utilities pursue and deliver grid services, products, and market opportunities (pricing, program, and procurement). Each term used in the framework is defined in Table ES-1.

Evolution in Grid Services and Products

Recent evolutions in electric utility grid services and products are driven by important technological and economic trends. For example, declines in the cost of interval metering created opportunities to measure consumption and, in some cases, production of a much wider array of grid services at residential homes and small businesses. Additionally, distributed generation (DG) adoption has increased dramatically over the past five years, driven, in part, by declining technology costs (Barbose et al., 2017).

As a result of these and other technological and economic trends, the electric utility industry is witnessing evolutions in retail rate designs and compensation reforms for various types of distributed energy resources (DERs) (e.g., solar PV, battery storage systems). The industry is also exploring new rate offerings, innovative programs, and novel procurement approaches all to ensure a more reliable and resilient grid, and to meet changing customer demands.

Table ES - 1. Description of the Concept or Definitions of Each Term Used in the Framework

Dimension	Term	Concept or definition
Directions	Grid services and products	*New or evolution of existing systems or items used in the delivery and consumption of electricity by end-use customers*
	Market opportunities	*Promoting the expansion of new or existing technologies or business opportunities, either directly for electric utilities or with third-party businesses*
Features	Attributes	*Reflecting the qualities or features of products and/or grid service(s) utilities are providing to customers, or that customers are providing to the utility*
	Locational	*Reflecting locational delineation in the cost of the grid service(s) being delivered by the utility to the customer or in the value of the grid service(s) being delivered by the customer to the utility*
	Temporal	*Reflecting temporal delineation in the cost of the grid service(s) being delivered by the utility to the customer or in the value of the grid service(s) being delivered by the customer to the utility*
	Utility share of investment cost	*Reflecting the share of the total investment cost that the utility incurs to pursue new market opportunities*
	Investment cost responsibility	*Reflecting the entity responsible for ultimately paying the investment cost that the utility incurs to pursue new market opportunities*
	Asset ownership	*Reflecting the entity that ultimately owns the asset enabling the regulated utility to develop new market opportunities*
Administration and Regulation	Pricing	*A structure (e.g., tariff, bill payment) by which a customer pays the utility for providing service(s) or product(s) offered on a default, voluntary, or pilot basis*
	Program	*A structure (e.g., tariff, bill rebate or credit) by which a utility pays the customer or third-party for providing service(s) or product(s) offered on a default, voluntary, or pilot basis*
	Procurement	*Implicitly derived through some competitive process (e.g., RFP, auction) what a utility will pay the customer or third party (e.g., aggregator) for providing service(s) or product(s)*

There are several important evolutions across various features in the framework (see Figure ES-2). Residential demand charges and DG compensation reforms are partially unbundling attributes of energy services into specific capacity charges and compensation for exported energy, respectively. Retail pricing is also evolving towards differentiated pricing in specific hours of the day (e.g., peak/off-peak periods, coincident demand charges[2]). There are fewer examples at the far ends of the feature continuums. For example, New York's "value of DER" tariff compensates exported generation for more attributes than energy and capacity (e.g., environmental and reliability/load shifting values). Likewise, evolutions in locational features appear among non-wires alternatives (NWAs) at the distribution feeder level.

Figure ES - 2. Summary of Evolutions across Features in Grid Services and Products

A review of literature and regulatory dockets identified tailwinds driving evolutions in grid services and products, including (see Figure ES-3):

- Non-DER pricing reforms, as well as DER pricing and programs, are driven by utility financial concerns about equitable revenue collection that fully recovers embedded costs but also addresses cost-shifting from participating customers to non-participating customers.
- DER integration and innovation are driving DER pricing and program evolutions as the continued cost declines and increasing adoption of technologies like distributed solar PV necessitate changes in the basis for incentive support.
- State and federal policy and financial support of investment in new technologies are driving the development of new types of utility retail pricing, programs, and procurement. For example, rates for electric vehicle (EV) charging are designed to encourage off-peak charging and improve customer economics for EV adoption. Also, some novel demand response (DR) programs are focused on flattening system load shapes by shifting consumption into middle-of-the-day periods to manage excess energy production from increasing concentration of variable renewable energy resources.

There are also several headwinds that may limit further evolution of grid services and products, including (see Figure ES-3):

- Concerns about limited consumer engagement are restraining non-DER pricing reforms that may increase customer bills and bill volatility, or may create challenges to transitioning customers to time-based rates (TBRs) and demand charges. These rates may also be

[2] Coincidence is based on the simultaneous demand of a customer with the sum of demand of a group of customers during a specified period (e.g., monthly, annual).

particularly impactful on vulnerable populations that may be less knowledgeable and/or capable of instituting behavioral changes or investing in control technology to reduce consumption during the more expensive on-peak periods.

- Solar industry advocates and DER providers are concerned about how DER compensation reforms may lead to reduced investment. The higher frequency of changes to future compensation levels may create uncertainty for customer investment decisions. Likewise, net billing arrangements, which compensates exported generation at a wholesale or avoided cost energy rate and DER customers purchase power at full retail rate, may increase bills for DER customers relative to net metering arrangements, though the magnitude depends on differences between retail and compensation rates, DG system size, and customer load profiles.
- Utility financial concerns driving many evolutions are also hindering evolutions among other grid services and products. For example, utilities have historically avoided pursuing demand-side management efforts under existing utility business models because they are predicated on deferring the need for future utility capital investment.

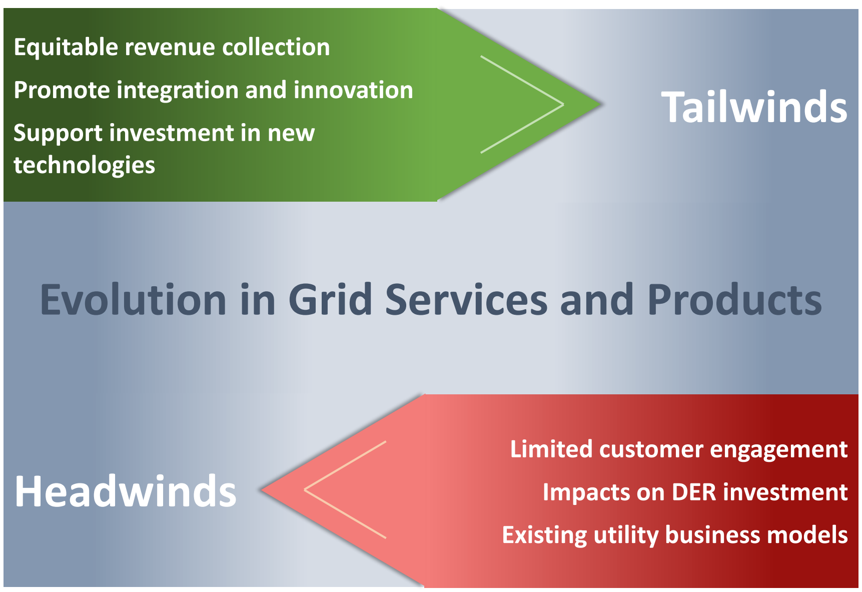

Figure ES - 3. Summary of Tailwinds and Headwinds for Evolution in Electric Utility Grid Services and Products

Evolution in Market Opportunities

Evolution in market opportunities is primarily driven by interest, in some states, in potentially having regulated electric utilities play an integral role in promoting the expansion of new or existing technologies or business opportunities. For example, electrification of the transportation sector and emerging DG technologies (e.g., behind-the-meter energy storage) are readily identified as opportunities where utility support could be instrumental, and possibly necessary, in driving down investment costs and increasing technology adoption. In addition, the growing digitalization of the electric industry creates new opportunities for regulated electric utilities to better support existing electric customers as well as third-party businesses. Various states and utilities have proposed or are testing alternative approaches that offer new roles and opportunities for regulated electric utilities

There are several important evolutions in market opportunities across various features in the framework (see Figure ES-4). Upfront investment costs are either partially or fully borne by utilities. The recovery of investment costs is similarly limited to either all customers or participating customers. Finally, in most cases, utilities or participating customers own the asset, with ownership sometimes transferring to the participating customer after all costs have been paid to the utility, particularly in the case of financing programs.

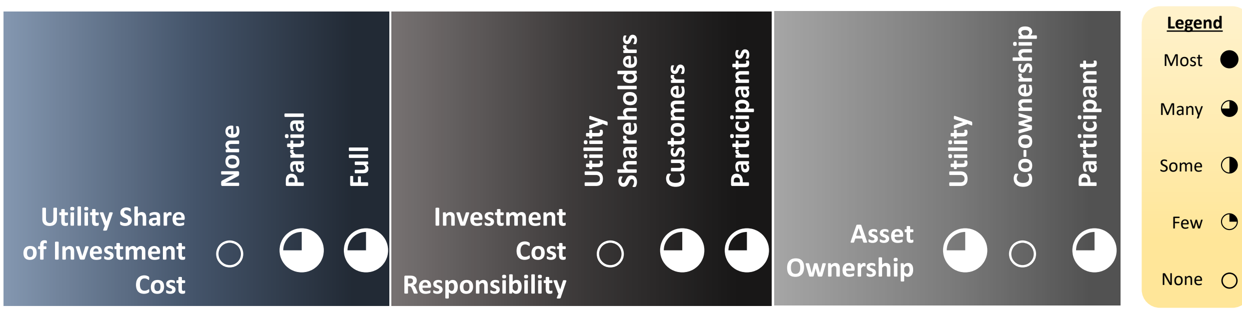

Figure ES - 4. Summary of Evolutions across Features in Market Opportunities

A review of literature and regulatory dockets identified tailwinds driving evolutions in market opportunities, including (see Figure ES-5):

- Utilities may be positioned to address certain market failures that include, reaching certain underserved customer groups (e.g., low income) and facilitating the development of a competitive market or to directly provide grid services and products where no competitive market currently exists.
- The electric utility's ability to procure lower cost capital may further provide electric utilities with a competitive advantage over third-party providers creating opportunities to meet public policy goals at lower total overall cost.
- Electric utilities have primary knowledge of their systems enabling them to deliver products in a more organized and systematic way that better supports the grid to meet its needs on a locational and temporal basis.
- In the case of utility data services, consumption data could better engage customers and utility system data may drive more cost-effective third-party investments in the grid.

There are also several areas of concern acting as headwinds which are hindering further evolution in market opportunities, including (see Figure ES-5):

- The introduction of electric utilities into new or expanding markets to promote short-term market failures may limit long-term market growth and development.

- In some cases, it may be problematic to assume that the utility can successfully expand into new and existing market opportunities, given its limited prior successful experience with innovation vis-à-vis private enterprise which must survive in a competitive market by being innovative
- Privacy and cybersecurity concerns cut across evolutions that increase access to customer data and share utility system data.

Figure ES - 5. Summary of Tailwinds and Headwinds for Evolution in Electric Utility Market Opportunities

Implications for Regulators and Policymakers

In the discussion of tailwinds and headwinds, there are several common policy issues and stakeholder concerns regulators and policymakers should be aware of:

- First, concerns about utility financial viability and business models drive interest in DER compensation reform and also a number of market opportunities that create possibilities for new capital investment and/or new revenue streams for the utility.
- Second, customer fairness and equity concerns continue to be a top priority for regulators, especially as retail rate and DER compensation reforms are considered. In some cases, regulators are creating new customer classes (e.g., based on whether they have DG systems) to better reflect cost causation and limit opportunities for cost shifting. Regulators, policymakers, and utilities are also increasingly attuned to low- and moderate-income customers and ensuring fair and equal access and opportunity for them to take advantage of new technologies, pricing, and programs.

- Third, differing perspectives on the appropriate role(s) for utilities in developing nascent markets and technologies may serve as tailwinds or headwinds for new market opportunities, depending on regulators' perspectives on the utility franchise. Expanding utility markets beyond traditional grid services and products were considered as either as tailwinds or headwinds — aiding or impairing market development.

Important and related themes emerge from this assessment of recent trends suggesting regulators and policymakers should formulate clear and consistent policy goals around the following two issues:

- Opportunities **increasing competition** to serve the energy generation needs of retail customers. Reforms that drive increases in NWAs and DER pit utility investments against customer investments and may erode the exclusivity of the utility franchise. In contrast, utility ownership of community or customer-sited solar that excludes or supplants opportunities for third parties, as well as reforms to DER compensation, that reduce financial viability of their investment may maintain or strengthen the firmness of the utility franchise boundaries.
- Opportunities driving **greater innovation** within and outside the electric industry. Electric utilities are innovating by developing novel financing mechanisms support the adoption of DERs, as well as by creating new market opportunities providing data services to support third-party commercial enterprises' efforts to reach customers more efficiently and effectively. There are also electric utility efforts to enable broader innovation in other industries, where utility investment in EV charging infrastructure could promote greater EV ownership and enable utility control of these resources to provide grid services.

1. Introduction

The electric industry evolved and expanded the types of grid services and products delivered to customers from the beginning of the 20th century to today. Electricity services initially encompassed just energy (kWh) for lighting and subsequently powering of machines (Hausman and Neufeld, 1984). But as the demand for more reliable electricity increased, and among a greater range of electricity-consuming end-uses, the number of services a utility needed to procure and provide to serve its customers likewise increased to include: energy, capacity, reactive power, spinning reserves, supplemental reserves, regulation reserves, and black-start reserves (NERC, 2010).

This evolution also expanded beyond supply-side generation resources for the provision of some of these services. For example, in the 1950s and 60s, electric utilities found a viable alternative in certain types of demand side resources that were willing to reduce load to maintain reliability, thereby providing a capacity service to the utility (EDP, 2016). Over the past 15 years with the advent of organized wholesale markets, demand side resources have been authorized to provide nearly all bulk power system services (IRC, 2016). With the widespread deployment of advanced metering infrastructure (AMI) in the last several years (Institute for Electric Innovation, 2017), utilities are now in the position to expand their service offerings even further into the data realm.

The electric industry also has a history of delivering products to customers that are continually expanding. At the onset of the electric industry, Thomas Edison provided customers with incandescent lamps and light bulbs so they could then buy the electricity service offered by Edison Light Company in New York City (Hausman and Neufeld, 1984). In the 1970s, federal and state policy advocated for the more efficient use of electricity from end-use devices (Wulfinghoff, 2000), and electric utilities took on the role of demand side management (DSM) program administrators. In some cases, electric utilities delivered DSM products, including more efficient and/or controllable lighting, motors, and pumps (Nadel, 1992). Recently, utilities have begun to dramatically expand the scope of products they sell to consumers including electric vehicle (EV) chargers, solar photovoltaic (PV) systems, and end-use technologies (e.g., heat pump water heaters) (Blansfield, et al., 2017).

Regulated electric utilities traditionally served retail electricity markets with explicit service and financial boundaries. Industry deregulation efforts in the 1990s and early-2000s opened some market opportunities for electric utilities as they spun off energy retailers and energy service companies (ESCOs), though subject to “ring-fencing” and other regulatory financial oversight. Recent societal, economic, and technological shifts are presenting regulated electric utilities with new market opportunities (Cross-Call et al., 2018).

This report focuses on the more recent changes and evolutions in grid services, products, and market opportunities regulated electric utilities are offering to their customers, as well as new market opportunities. For clarity, “grid services and products” are considered to be what the electric utility sells to or buys from customers.[3] It is also important to note that the word "customer" is used throughout this report as an overarching term that refers to two different entities: 1) households and businesses directly transacting the grid services and products; and 2) third-party businesses that may be buying or selling new electric utility grid services and products that support the third-party business's offerings. As such, the report does not identify or discuss the sale of services and products by non-utility entities (e.g., third-party demand response (DR) providers) to homes and businesses, though notes these companies have been increasing in number and market size in recent years (AEE, 2017) and their business activities are directly affected by electric utilities.

While there are notable trends towards large commercial and industrial (C&I) customer direct access and procurement of renewable energy, this report focuses on evolutions for mass market electricity customers (i.e., residential and small C&I customers). Also, many of the evolutions in this report for mass market customers already exist among large C&I customers. For example, many large C&I customers use advanced meters, take electricity service under mandatory time-of-use (TOU) or demand charges, and have dedicated facility managers evaluating energy consumption data.

As the title of the report suggests, the focus is primarily on "evolution" in electric utility grid services, products, and market opportunities. "Evolution" is defined as the development of a new or different way in which: a) customers receive and/or pay for electric utility services and products; or b) electric utilities support broader market development opportunities (which themselves likely result in utility grid service or product offerings). Notwithstanding the broad definitions of "services", "products", "market opportunities", and "evolution," an analytical approach is applied to identify current examples and categorize them by key features. Importantly, the report does not make value judgements as to whether evolutions are "good" or "bad" but, rather, notes business and policy motivations driving the evolutions and implications for certain industry stakeholders.

Prior literature has focused on specific subsets of the evolving electric utility industry. Several reports catalog and summarize details of new utility pricing and programs arranged thematically, like changes in utility rate designs for distributed energy resources (DERs) (Stanton, 2015a; NCCETC, 2017), rate designs for energy efficiency (EE) (Baatz, 2017), and grid modernization policies (Proudlove et al., 2017). Similarly, there is a range of literature on non-utility market size and key trends for specific technologies (GTM and ESA, 2017) or industries (AEE, 2017). Finally, more conceptual literature suggests directional movement towards more advanced grid service and product offerings (Glick et al., 2014; Satchwell et al., 2015; Lazar, 2016b; Cross-Call et al., 2018).

[3] Literature on electric utility grid services and products does not clearly define the two terms. For example, Blansfield et al. (2017) uses "services" and "products" interchangeably. Similarly, Pokorny (1988) uses "products" to describe everything a utility sells to its customers and includes customer service as an example of products. Therefore, the report does not define "products" and "services" differently but instead use the phrase "grid services and products" to describe the range of what the electric utility sells to or buys from retail customers.

This report builds on and references prior work with more recent examples across a wider range of grid services, products, and market opportunities. The report also presents a more comprehensive and refined framework to categorize evolutions across several dimensions to enable comparisons across major evolutionary areas. Last, the report ties evolutions to the points of view among regulators, policymakers, utilities, and advocates driving and opposing evolutions (i.e., “tailwinds” and “headwinds”).

The remainder of the report is organized as follows: Section 2 details the data sources and analytical approach; Section 3 describes the organizational framework; Section 4 describes proposals related to evolutions in grid services and products and discusses topic-specific tailwinds and headwinds; Section 5 describes proposals related to evolutions in market opportunities and discusses topic-specific tailwinds and headwinds; and Section 6 concludes with implications for regulators and policymakers.

2. Data Sources

In order to identify and understand the drivers for evolution in utility grid services, products, and market opportunities, the analysis described in this report relied on a representative database of recent regulatory filings by electric utilities and major legislation pertaining to electric utilities. Over a six-month period (June to November 2017), a number of industry periodicals, digests, and other publications were reviewed to identify the representative sample, including:

- Advanced Energy Economy (AEE) PowerSuite's Docket Digest;
- e9 Insight monthly newsletters;
- E&E News;
- Greentech Media;
- Midwest Energy News;
- North Carolina (NC) Clean Energy Technology Center's 50 States of Solar and 50 States of Grid Modernization quarterly reports;
- National Governors Association (NGA)'s State Clean Energy Actions Database;
- Politico;
- SNL Regulatory Roundup;
- U.S. Energy News; and
- Utility Dive.

These sources provided over 50 recent examples where state regulatory agencies, legislatures, and electric utilities put forth new proposals or recommended changes to existing product or service offerings. Data collection efforts focused on activities promulgated by or affecting regulated investor-owned electric utilities.[4] This meant reviewing public filings in state utility regulatory proceedings, statutes from legislative sessions and utility reports, websites, and presentations to better understand the specifics of the changes being proposed or instituted.

The intent of this research effort is to take a *snapshot* in time of how the regulated electric utility industry is evolving in the services and products it is offering to or procuring from consumers and businesses, as well as the markets it is seeking to support and enable. As such, the examples in this report are limited to activities that occurred within the last two to three years, with an emphasis on those that either culminated or were initiated in 2017. Some of the examples were of activities in their earliest stages, lacking substantial detail for how they might be fully implemented at some future date. In other cases, there were examples of firmly established activities but for which recent changes or adjustments were being made to improve their efficacy. Finally, the database of examples incorporated proposals either in their formative stages of review or that had been ordered on by regulators or legislators, regardless if successful or had been rejected.

[4] In some cases, municipal and cooperative utilities have made evolutions similar to their regulated investor owned utility (IOU) counterparts. However, this report is focused on recent efforts by IOUs.

3. Framework for Characterizing Evolutions in Grid Services, Products, and Market Opportunities

The analysis uses an organizational framework for categorizing the recent proposals in the database. By applying this qualitatively rigorous approach, the analysis is able to better characterize the main pathways of evolution in regulated electric utility grid services, products, and market opportunities. Evolutions are occurring not only along retail pricing, program, and procurement approaches but also in the way traditional grid services are being bought and sold by utilities (in non-traditional ways), as well as among new market opportunities. The framework builds on prior work that typically assumes two-dimensional spaces (Glick et al., 2014; Satchwell et al., 2015) or successive patterns of evolution (e.g., time-based rates (TBRs) progress from hourly to sub-hourly temporal dimensions).

The purpose of the framework in this report is two-fold: (1) to capture and categorize many possible evolutions and (2) to organize evolutions for the purpose of comparing and discussing tailwinds and headwinds. The framework is composed of three dimensions (see Figure 1): **directions of evolutions** (grid services & products, and market opportunities); **features of evolutions** (attribute, locational, temporal, utility share of investment cost, investment cost responsibility, and asset ownership); and **administration and regulation** of electric utility grid services, products, and market opportunities (pricing, program, and procurement). The dimensions are discussed and defined below.

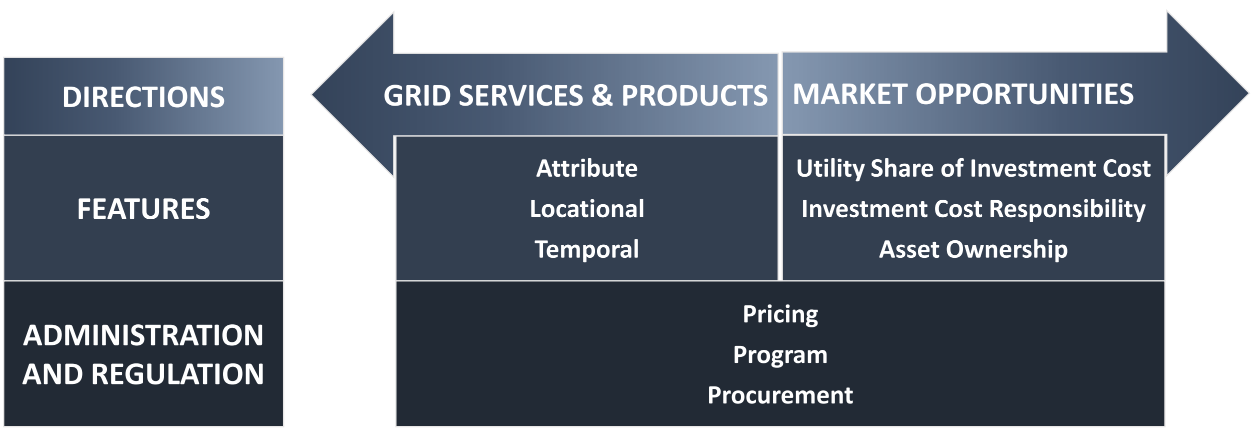

Figure 1. Framework Categorizing Evolutions in Electric Utility Grid Services, Products, and Market Opportunities.

3.1 Directions for Evolutions

The framework begins by describing two general directions in which evolutions are trending that are distinct and not overlapping.

Grid Services and Products. One direction of evolutionary trends is occurring in more traditional areas of grid services and products. Historically and more commonly understood, grid services and products are necessary to deliver electricity to customers and ensure system reliability (e.g., energy, capacity, frequency). Grid services and products also include customer support and other activities to engage customers (e.g., marketing). The term **grid services and products** represents the following concept:

New or evolution of existing systems or items used in the delivery and consumption of electricity by end-use customers.

Market Opportunities. Another direction of evolution trends is in expanding the market for electric utilities. These include market opportunities in nascent or undeveloped markets like energy storage and EVs, as well as new business opportunities like the sale of aggregated customer data and data analytics. The term **market opportunities** represents the following concept:

Promoting the expansion of new or existing technologies or business opportunities, either directly for electric utilities or with third-party businesses.

3.2 Features of Evolutions

The second dimension of the framework describes features of evolutions in electric utility services, products, and market opportunities along six continuums. It builds on the continuums of future retail rate design in Glick et al. (2014) by broadening their application beyond pricing, as well as specifying key points along each continuum. The first three continuums (attribute, locational, and temporal) apply exclusively to grid services and products and the last three continuums (utility share of investment cost, investment cost responsibility, and asset ownership) apply only to market opportunities.

3.2.1 Features of Grid Services and Products

Attribute. Electric utilities are increasing the granularity of grid services and product offerings to more accurately reflect their cost and value, and also reflect who is delivering (and ultimately paying for) them. Grid services and products may be bundled all together or, as suggested by recent evolutions, disaggregated into smaller component pieces. The attribute continuum is defined by two end points and a third space between: fully bundled, partially unbundled, fully unbundled. **Attribute** is defined in the framework as:

Reflecting the qualities or features of products and/or grid service(s) utilities are providing to customers, or that customers are providing to the utility.

Locational. Historically, utilities rarely differentiated the delivery or acquisition of grid services and products by grid location.[5] Recently, however, there has been increased recognition that end-use customers can provide a number of grid services at specific locations that may be more valuable than services provided elsewhere on the grid. The locational continuum is represented by three points: bulk-power system, regional/zonal, and distribution feeder. **Locational** is defined in the framework as:

Reflecting locational delineation in the cost of the grid service(s) being delivered by the utility to the customer or in the value of the grid service(s) being delivered by the customer to the utility.

Temporal. Most existing metering, communications, and back office system infrastructure (e.g., meter data management, billing) has largely been capable of only recording and pricing electricity services, at most, on an hourly basis.[6] By introducing more temporal granularity, electric utilities are better able to reflect the cost of the grid services being delivered by the utility to the customer or in the value of the grid services being delivered by the customer to the utility. This temporal delineation in the framework exists at three levels: annual/seasonal, hourly, or sub-hourly. **Temporal** is defined in the framework as:

Reflecting temporal delineation in the cost of the grid service(s) being delivered by the utility to the customer or in the value of the grid service(s) being delivered by the customer to the utility.

3.2.2 Features of Market Opportunities

Utility share of investment cost. At present, there is increased interest among regulators in allowing utilities to make investments to promote or enable market opportunities, either for utilities or third parties. Typically, utilities make the upfront financial investment taking on the full share of investment costs. As third-parties and customers begin to interconnect and invest in technology-enabling infrastructure (e.g., EV charging infrastructure), however, the upfront investment cost may be incurred by or shared among customers, utilities, or third-parties. This feature in the framework exists at three points: no utility share, partial utility share, or full utility share. **Utility share of investment cost** is defined in the framework as:

Reflecting the share of the total investment cost that the utility incurs to pursue new market opportunities.

Investment cost responsibility. Cost recovery for utility investments has traditionally occurred in general rate cases and reflected in the authorized revenue requirement used to set retail electricity rates. In the case of voluntary programs (e.g., EE), regulators may also deem some portion of costs are to be paid by customers who participate in programs. Evolutions in electric utility market opportunities are similarly asking regulators to assign cost responsibility based on who benefits the most from the

[5] This statement does not include the development of wholesale markets and prices that reflect location-based constraints in the bulk power system (i.e., locational marginal prices).
[6] While large C&I customers typically have meters than can capture 15-minute maximum demand levels, they are generally only used for hourly energy as part of time-of-use (TOU) programs.

investment. This feature in the framework exists at three points: customers, participants, and utility shareholders. **Investment cost responsibility** is defined in the framework as:

Reflecting the entity responsible for ultimately paying the investment cost that the utility incurs to pursue new market opportunities.

Asset ownership. Utility investments in electricity generating, transmission, and distribution systems are owned and operated by the utility.[7] There has been an implicit delineation at the customer meter base separating utility assets from customer assets. As retail market opportunities evolve towards customer end-use technologies, distributed resources, and customer data, new questions about the most appropriate delineation point and more generally about asset ownership are being considered. This feature in the framework exists at three points: utility ownership, co-ownership, and participant ownership. **Asset ownership** is defined in the framework as:

Reflecting the entity that ultimately owns the asset enabling the regulated utility to develop new market opportunities.

3.3 Administration and Regulation of Grid Services, Products, and Market Opportunities

The third, and final, dimension of the framework characterizes the way in which electric utilities administer their grid services and products and is applicable across all directions and features of evolutions. The dimension also reflects the primary ways in how electric utilities are regulated.

At the most basic level, customers pay their utility through some form of pricing for partial or full electricity service. In vertically integrated utility (VIU) retail markets, pricing is comprised of the generation and/or procurement of the electric commodity (inclusive of the supporting services to ensure power quality and reliability), as well as the delivery of electricity over bulk power and distribution system infrastructure (i.e., transmission and distribution (T&D)). In competitive retail electricity markets, the utility is obligated to provide delivery service to all customers in its service territory and may or may not also be the customer's commodity electricity supplier.

Pricing. Electric utilities specify the pricing amount and terms of service in a tariff to identify exactly how these services will be charged to consumers, subject to regulatory approval. Electric utilities may offer more than one tariff for a particular customer class, in many cases offering both a default pricing option, as well as one or more alternatives to the default, some being provided exclusively on a temporary (i.e., pilot) basis. However, utilities are also beginning to deliver other types of value-added services to customers, aside from the electric commodity and its associated support services (e.g., customer or grid data services to businesses). **Pricing** is defined in the framework as:

[7] Utilities in restructured states only invest in and receive cost recovery for a subset of these asset types.

A structure (e.g., tariff, bill payment) by which a customer pays the utility for providing service(s) or product(s) offered on a default, voluntary, or pilot basis.

Program. Electric utilities are able to acquire a subset of electricity services (e.g., load reductions that serve as a capacity resource) from customers.[8] Similar to pricing tariffs, programs in which customers are paid for providing a service or product to the utility are also typically specified in a separate program tariff and subject to regulatory approval. These program tariffs often define the conditions under which payment will occur, including interconnection requirements, notification requirements, communication infrastructure requirements, performance requirements, as well as penalty and payment provisions. Historically, the utility acquired different types of grid services (e.g., peak capacity, energy) from customers via programs (e.g., performance payments for load management programs, rebates for energy efficiency programs). More recently, the utility has also included programs crediting customers for net electricity of distributed generation to its portfolio (e.g., net metering of solar PV systems). As with pricing opportunities, utility program offerings can be the default (e.g., Peak Time Rebate load management programs, or net metering billing arrangements for customers with solar PV systems) or an optional program a customer can choose to participate in, even if it is a temporary pilot program. **Program** is defined in the framework as:

A structure (e.g., tariff, bill rebate or credit) by which a utility pays the customer or third-party for providing service(s) or product(s) offered on a default, voluntary, or pilot basis.

Procurement. One of the most important and fundamental electric utility roles is the balancing of electric load and supply. In order to maintain an adequate balance to provide reliable electric service, utilities must self-generate and/or procure sufficient electric supply from other providers. In addition to procuring the electricity commodity, utilities may also seek to procure other services (e.g., IT infrastructure) or products from non-utility entities. Until recently, electric utilities have not generally procured grid services and products directly from customers through competitive means, focusing instead on programs available to all similarly situated customers and with pre-established compensation amounts (e.g., monthly bill credit for participating in air conditioning load management program) that would not be considered procurement in the framework.[9] However, as non-utility entities have sought to create business opportunities for aggregating large numbers of customer able to provide specific services to electric utilities, regulators and policymakers have been increasingly willing to expand the use of competitive procurement processes into these new product or service areas. **Procurement** is defined in the framework as:

Implicitly derived through some competitive process (e.g., RFP, auction) what a utility will pay the customer or third party (e.g., aggregator) for providing service(s) or product(s).

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[8] Such customers are frequently called "prosumers" (Toffler, 1980).

[9] While electric utilities used competitive procurement processes to procure energy supply or load reductions in the 1990s (e.g., DSM bidding programs), it was uncommon that utilities allowed customers to directly participate in the procurement. Recent evolutions suggest more direct customer participation in procurement, among other things.

3.4 Applying the Framework to a Discussion of Evolutionary Trends

The various elements of the framework described in the previous section can be combined to produce a multi-dimensional representation (see Figure 1). The framework, along with examples in the database, provides a snapshot of what the evolution in retail electric utility grid services, products, and market opportunities looks like. The remainder of the report draws on the framework and examples to reveal overall trends in the way the regulated electric utility industry is evolving. In particular, the subsequent section describes what is motivating these changes by way of macro- or micro-level headwinds and tailwinds, which allows for a more comprehensive picture of the key drivers for this evolution.

4. Evolution in Grid Services and Products

Recent evolutions in electric utility grid services and products are driven by important technological and economic trends. For example, declines in the cost of interval metering created opportunities to measure consumption and, in some cases, production of a much wider array of grid services at residential homes and small businesses. Additionally, distributed generation (DG) adoption has increased dramatically over the past five years, driven, in part, by declining technology costs (Barbose et al., 2017).

As a result of these technological and economic (i.e., declining costs) trends, utilities are now expanding existing opportunities, and creating new ones, that promote buying/selling of these various grid services from/to customers or, more recently, aggregators of retail customers (ARCs). Specifically, the retail electric utility industry is witnessing evolutions in retail rate designs, predominantly at the residential level for basic service but also to support requirements of specific new end-uses (e.g., EV charging). In addition, the evolution extends into compensation reforms for various types of DERs, like solar PV systems and battery storage systems, which have historically operated under net-energy metering (NEM) arrangements where generation exported to the grid is credited at the full volumetric retail electricity rate. Last, the industry is testing out new rate offerings, innovative programs, and novel procurement approaches to ensure a more reliable and resilient grid. The different aspects of the evolutions in grid services and products are discussed below, specifically in retail tariff pricing, DG compensation programs, and new areas for pricing, programs, and procurement.

4.1 Non–DER Pricing Reforms

Reforms in retail pricing are evolving the ways in which customers pay for the grid services and products they consume and are mostly occurring in the residential customer class. Table 1 shows that a handful of states (e.g., California, Massachusetts) have committed to moving all of their residential customers onto default TOU rates, while a few other states are considering such a transition in current or future regulatory proceedings (e.g., Colorado, New York). Concerns about transitioning all residential customers to TOU are prompting a number of states and utilities to pursue innovative pricing pilots (e.g., Xcel in Colorado and Minnesota, utilities in Hawaii and California). There is interest in introducing demand charges at the residential level, but very few examples of utilities that have formally submitted a proposal (e.g., Xcel in Colorado) and regulators that have approved them (e.g., OG&E in Arkansas). Instead, those utilities seeking to pursue such rates are doing so first in pilot form (e.g., Alabama Power, Consolidated Edison).

Table 1. Sample of Non-DER Pricing Reforms

State	Docket/Legislation	Description
AL	U-5224	Residential demand charge pricing pilot (Alabama Power)
AR	16-052-U	Residential and general service TOU & demand charge rates (OG&E)
CA	R.12-06-013	Residential default TOU rates and supporting pilots (all IOUs)
CO	17M-0204E	Residential voluntary/default TOU & demand charge rates (all IOUs)
HI	2014-0192	Residential TOU rate pilots (all IOUs)
MA	14-04-C	Residential default TOU rates for distribution costs only (all IOUs)
MD	PC-44	Residential TOU rate pilots (all IOUs)
MN	E002/M-17-775	Residential TOU rate pilot (Xcel Energy)
NY	15-E-0050	Residential demand charge pricing pilot (Consolidated Edison)
NY	14-M-0101	Residential and small commercial voluntary/default TOU rates (all IOUs)
OH	17-1234-EL-ATA	Residential TOU rate (Ohio Power Company)

Within the framework, a number of trends emerge from these pricing reforms (see Figure 2). First, the industry is increasingly considering, and in a number of places implementing, an unbundling of the energy and capacity services and charging residential customers explicitly for capacity costs through residential demand charges. There were no movements to price other grid services for retail customers (e.g., ancillary services) separately. Second, there has yet to be any substantive movement towards greater locational granularity in the rates being charged to customers, despite increased industry interest in better managing load at specific feeders on the distribution system (Gahl et al., 2018). Third, movement towards greater temporal granularity has been limited to aggregated hourly periods of the day (i.e., peak/off-peak periods, coincident demand charges[10]). Within the sample, there were no movements towards finer temporal granularity, like sub-hourly pricing levels for basic electric service, for residential and small C&I customers.

[10] Coincidence is based on the simultaneous demand of a customer with the sum of demand of a group of customers during a specified period (e.g., monthly, annual).

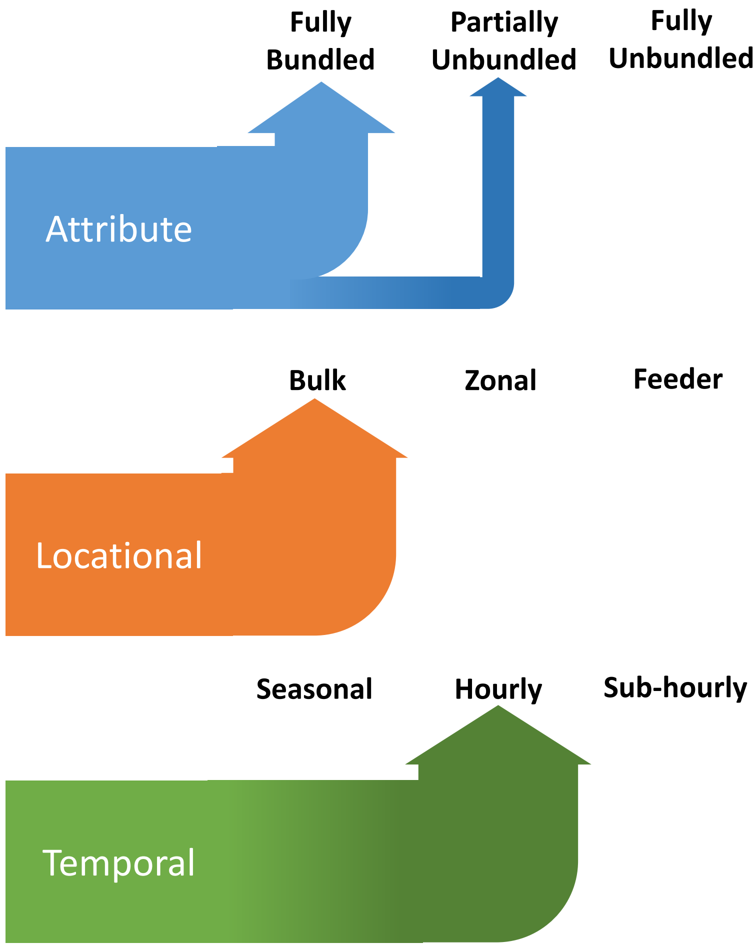

Figure 2. Trends in Non-DER Pricing Reforms towards Partial Attribute Unbundling and Hourly Timescales[11]

There are two categories of tailwinds driving these reforms forward (see Figure 3). First, AMI business cases have frequently included benefits from greater penetration of TBRs at the residential level (NETL, 2008). With over half of the existing advanced meters on U.S. households installed between 2012 and 2016 (Institute for Electric Innovation, 2017), regulators and policymakers are now encouraging utilities to capture those benefits, either through increased utility commitment to better designed and better marketed voluntary TBR (e.g., Maryland, Ohio) or making it the default rate offering (e.g., California – see text box). Alternatively, utilities proposing new AMI deployments recognize the value of implementing pricing pilots to both support their business case and help clarify how the utility might pursue a broader rollout of TBR in the future (e.g., Xcel in Colorado).

[11] A repeating figure structure is used here and throughout the report intended to generally represent the magnitude of evolutions in electric utility grid services, products, and market opportunities at particular points along the continuum of features. The widths of the arrows indicate *relative magnitude* where larger widths suggest greater evolution than arrows with smaller widths. The arrow widths are based on the database sample and should not be considered perfectly representative of the entire population of reforms being undertaken in the electric utility industry.

Second, sales growth is slowing, if not flat, in most jurisdictions (EIA, 2017). This will adversely affect electric utility revenue growth between rate cases when rates are dominated by volumetric energy charges, which may hamper the utility's ability to fully cover their embedded costs if they do not have revenue decoupling mechanisms in place. A number of utilities have publicly supported the idea of moving more costs for residential and small commercial customers into billing determinants that may be more stable and cost causal (i.e., demand charges, fixed customer charges) or impose minimum bill requirements all to ensure sufficient fixed cost recovery (Hledik, 2014; Lazar, 2016a).

TRANSITION TO RESIDENTIAL DEFAULT TOU RATES

The California Public Utilities Commission issued an order on July 3, 2015 setting in motion a transition to default TOU rates for all of the state's residential customers of IOUs in the 2019/2020 time frame (CPUC, 2015). Some stakeholders promoted the transition to default TOU citing reasons like economic efficiency, long-term cost savings, and environmental benefits. Other stakeholders raised concerns about adverse impacts on customers, the implications of the general lack of customer engagement, and the effects of evolving load curves from DERs on existing TOU rate designs. These stakeholders generally supported greater utility efforts to attract customers under a voluntary TOU offering. To help address as many of the concerns as possible, the Commission ordered a state-wide multiyear series of pricing pilots that included different enrollment approaches to learn more about the anticipated transition.

In contrast, a number of stakeholder groups have raised myriad concerns about such rate reforms that function as headwinds (see Figure 3). Environmental advocates as well as EE/PV industry groups contend that the introduction of demand charges will likely discourage investment in technologies that lower retail electric sales (Hledik, 2014). Consumer advocates contend that TOU rates could be considered a regressive tax on low-income customers who they believe generally use less electricity than the average customer and are less capable of instituting behavioral changes or investing in control technology to reduce consumption during the more expensive on peak period (AARP et al., 2010; Cappers et al., 2016; Hledik and Faruqui, 2016). They also raise concerns that demand charges and TOU rates could increase average bills and bill volatility (Alexander, 2010; Hledik and Faruqui, 2016). Consumer awareness about total monthly usage, peak demands, and period usage, for example, is likely very limited which may further create challenges for transitioning customers to more TBRs and demand charges (Faruqui et al., 2010; Hledik, 2014; Acadia Center, 2017).

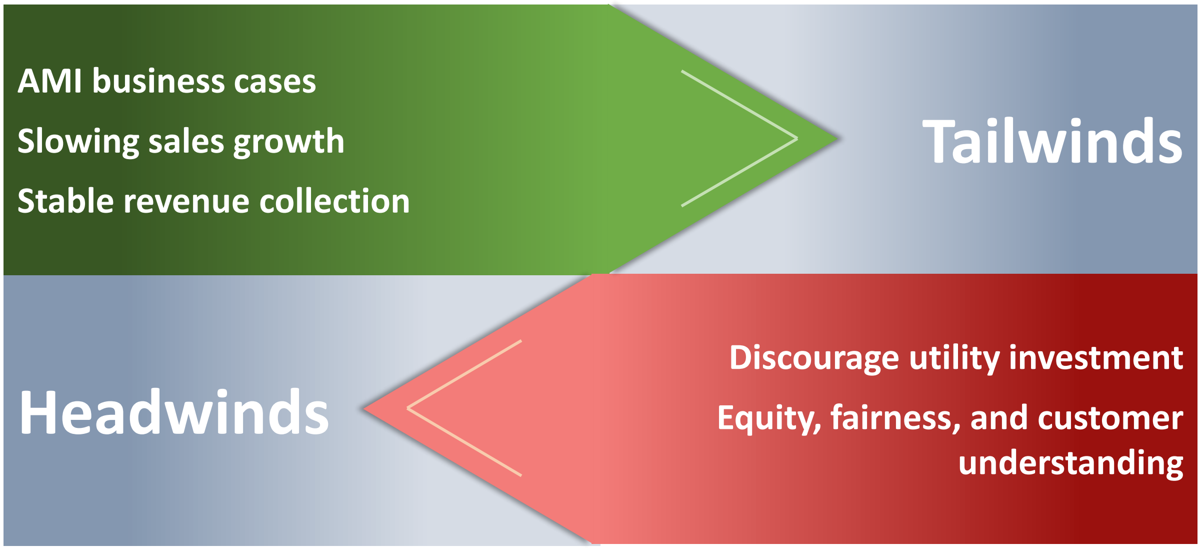

Figure 3. Non-DER Pricing Tailwinds and Headwinds

4.2 DER Pricing and Program Reforms

A succession of legislative and regulatory actions at the state and federal level over the past four decades promoted the development of customer-sited generation resources and created a market for exported power (i.e., power generated in excess of the customer's onsite demand). At the federal level, PURPA in 1978 and the Energy Policy Act of 2001 advanced markets for power from non-utility generating sources. A more well-known mechanism at the retail level, and a key contributor to the dramatic increase in DG over the past five years, is NEM that credits DG owners for exported electricity production at the full retail electricity rate. Numerous states and utilities have made changes to compensating DG for exported electricity and are proactively considering fair and proper compensation for emerging energy technologies, like storage and EVs.

DER compensation reforms compensating exported DG system generation at a price different than the full retail rate suggests a trend towards 'net billing' approaches. Net metering and net billing are not the same and the differences may have significant implications for certain types of DG owners discussed later. Net metering essentially allows DG customers to generate credits for exported electricity and bank them for future use (typically subject to annual reconciliation), whereas net billing compensates exported generation at a wholesale or avoided cost energy rate and DG customers purchase power at full retail rate (NCCETC, 2017).

As of the publication of this report, 11 states had approved some form of compensation for exported DG output as either a reform to NEM or as a successor tariff (see Table 2). Another handful of states (e.g., Arkansas, Louisiana, and Texas) had pending decisions and even more states were exploring the costs and benefits of DG to inform potential compensation reforms. DG compensation reforms have largely focused on altering the energy (per kWh) rate paid by the utility for exported customer DG output based on either an avoided-cost rate (e.g., Arizona), wholesale energy rate (e.g., Indiana), or some administratively-determined percentage of the retail energy rate (e.g., Nevada and Utah). As such, most DG compensation reforms have partially unbundled the energy component of retail electricity rates.

Further along the evolutionary spectrum, New York, as part of its Reforming the Energy Vision (REV) proceeding, has established a DG compensation approach with attribute, locational, and temporal features (see Text Box) (NYPSC, 2017b). The "Value of DER" tariff in New York compensates exported generation with energy, capacity, environmental, and reliability/load shifting values. The reliability/load shifting value is based on locational system relief and hourly energy rates. In addition, a few states (e.g., Hawaii, Missouri, and Oregon) are implementing similar types of rate reforms (i.e., TOU energy rates, demand charges) for specific end-uses like EVs (e.g., PEPCO in Washington, D.C., PGE in Oregon, and utilities in Missouri).

Table 2. Sample of State-Level DER Pricing and Program Reforms

State	Docket/Legislation	Description
AZ	E-01345A-16-0036	Net billing with exported generation priced at avoided-cost energy rate
CA	15-04-012	TOU rate (successor tariff for customers after NEM cap reached)
DC	FC1143	EV TOU rate (PEPCO)
HI	2014-0192	Net billing with exported generation priced at avoided-cost energy rate ("grid-supply" option) or no compensation for exported generation ("self-supply" option)
IN	S.B. 309	Buy-all/sell-all with exported generation paid wholesale energy rate[12]
ME	2016-00222	Buy-all/sell-all with exported generation paid wholesale energy rate
MO	EW-2017-0245	Residential and EV TOU rates (all IOUs)
MS	2011-AD-2	Net billing with exported generation priced at avoided-cost energy rate
NH	DE16-576	Net metering with credits at 100% energy and transmission charges and 25% distribution charges
NV	17-07026	Net metering at decreasing credit rates (floor is 75% of retail rate)
NY	15E-0751	Net metering with exported energy credit based on stack of values for different grid and other services provided
OR	UM 1811	EV TOU rate and demand charge (Portland General Electric)
UT	14-035-114	Net metering with export credit at 90% energy rate (Rocky Mountain Power)
VA	PUR-2017-00099	Buy-all/sell-all (small agricultural only)

Within the framework, DG compensation reforms fit within the directional trends of grid services and products as they promote the buying of energy, capacity, and ancillary services from customers or third-party aggregators (see Figure 4). A small subset of reforms provide greater granularity in the location-based DG compensation level, setting them zonally. Of the few utilities pursuing more temporal granularity, the majority are instituting hourly (e.g., period) compensation levels for exported

[12] Unlike net metering or net billing, "buy-all/sell-all" programs do not credit customers at full retail rate for energy consumed on-site (i.e., behind-the-meter).

DG output.

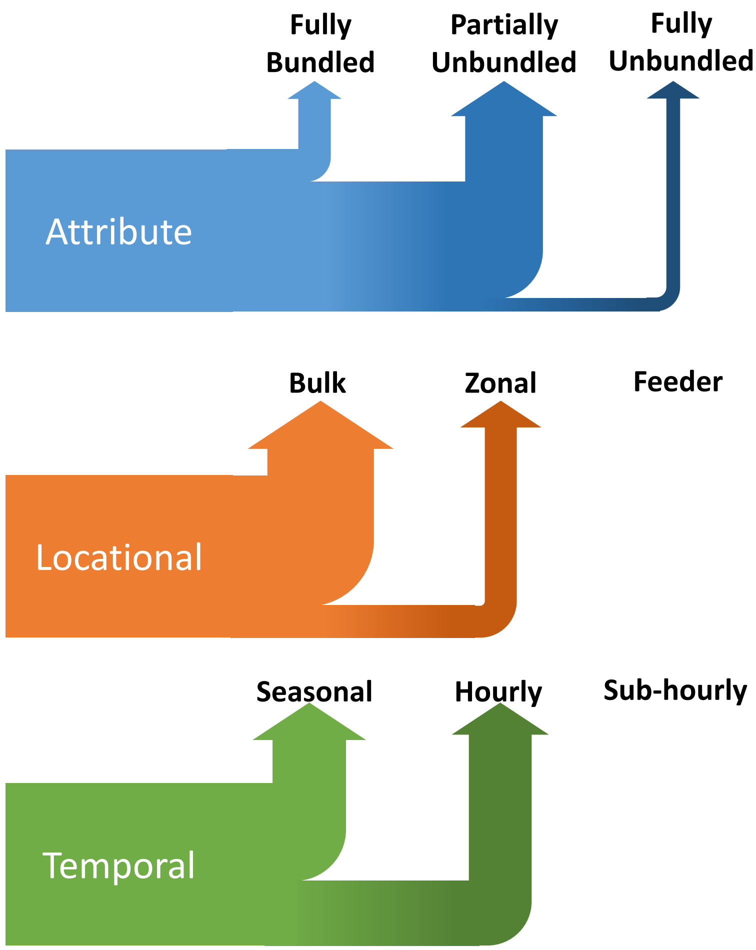

Figure 4. Trends in DER Pricing and Program Reforms towards Partial Attribute Unbundling

NEW YORK VALUE OF DISTRIBUTED ENERY RESOURCES

The New York PSC implemented the first phase of a novel DG compensation mechanism in September, 2017 to "enable a distributed, transactive, and integrated electric system" (NYPSC, 2017c). The Value of DER tariffs include four pricing components based on the range of benefits DERs provide to the New York utilities distribution networks. The Value of DER tariffs are a key component of the New York PSC's comprehensive Reforming the Energy Vision (REV) proceeding reforming utility roles, responsibilities, and regulatory frameworks.

DG compensation reforms are primarily driven forward by the objectives of fairly and equitably incentivizing technology adoption without driving significant cross-subsidization and, to a lesser extent, interests in reflecting DG-specific value streams (see Figure 5). Utilities have expressed concerns about over-compensating DG (EEI, 2016) along with potential financial impacts on achieved earnings and return-on-equity (Satchwell et al., 2014). As a related motivation, regulators and consumer advocates note potential cost shifting from DG owners (i.e., participants) to non-participating customers, which could be mitigated or removed entirely with DG compensation reforms (Barbose, 2017; Satchwell et al., 2017). The potential for and degree of cost shifting depends in large part on underlying retail rate design (e.g., California NEM study) and ability of net-metered DG to contribute to meeting RPS targets (e.g., Nevada NEM study), among other factors. Many utilities view the dramatic growth in distributed solar PV in some states (e.g., Nevada, California, Arizona) as evidence that incentive policies, like NEM, are no longer warranted (EEI, 2016).

Beyond these primary drivers, some utilities are reaching pre-specified caps on the amount of DG capacity enrolled in NEM, thereby forcing regulators and legislators to determine successor tariffs (NCCETC, 2017). DER providers are also supporting the determination of resource locational value (e.g., avoided marginal cost of capacity) and using that feeder-level information as the basis for new compensation schemes (Gahl et al., 2018).

Regulators and utilities are also recognizing that strategically designed retail rates can be effective at managing new forms of customer electricity consumption. For example, several prior EV pricing pilots successfully promoted off-peak EV charging by instituting retail rate designs with lower overnight rates (DOE, 2014). Also, unique EV charging programs (e.g., ConEd "Smart Charge New York") are offering customers compensation for charging during off-peak hours and contribute to the utility's overall goal of improving load factor[13], while at the same time collecting data and insights into customer charging behavior.

DER pricing and program reforms face several headwinds hindering development of more novel designs that move farther down the attribute, locational, and temporal continuums (see Figure 5). Solar advocates and providers are concerned about inconsistent application of DG compensation methodologies across utilities and states, and the frequency of changes to compensation levels that may create uncertainty for customer investment decisions and hinder the development of a robust DG market (SEIA, 2017). The development of California's NEM successor tariff explicitly considered the impact of changes on sustainable growth of the DG industry and mitigating adverse impacts on DG suppliers, in addition to utility financial and customer impacts (CPUC, 2016d). Also, implicit competition among DG and DERs may reduce existing and future value of particular resources and may depend on the integration of EE, DR, and DG savings goals. For example, distributed solar PV may be less coincident with utility system peak periods at increasing deployment levels and DG compensation may decline under TOU rates (Darghouth et al., 2015).

Furthermore, net billing arrangements may increase bills for DG customers relative to net metering arrangements, though the magnitude depends on differences between retail and compensation rates, DG system size, and customer load profiles (Cox et al., 2015). Net billing tends to be preferred by energy storage owners because of the ability to arbitrage, which may not ultimately address concerns about utility shareholder or customer impacts.

Finally, the lack of evolution in retail rate reforms towards differentiation in grid services and location greatly limits the ability to properly and fairly compensate DG customers with respect to attributes or location.

13 Load factor measures the capacity utilization of energy use and is the total amount of energy used divided by the peak demand during the same period.

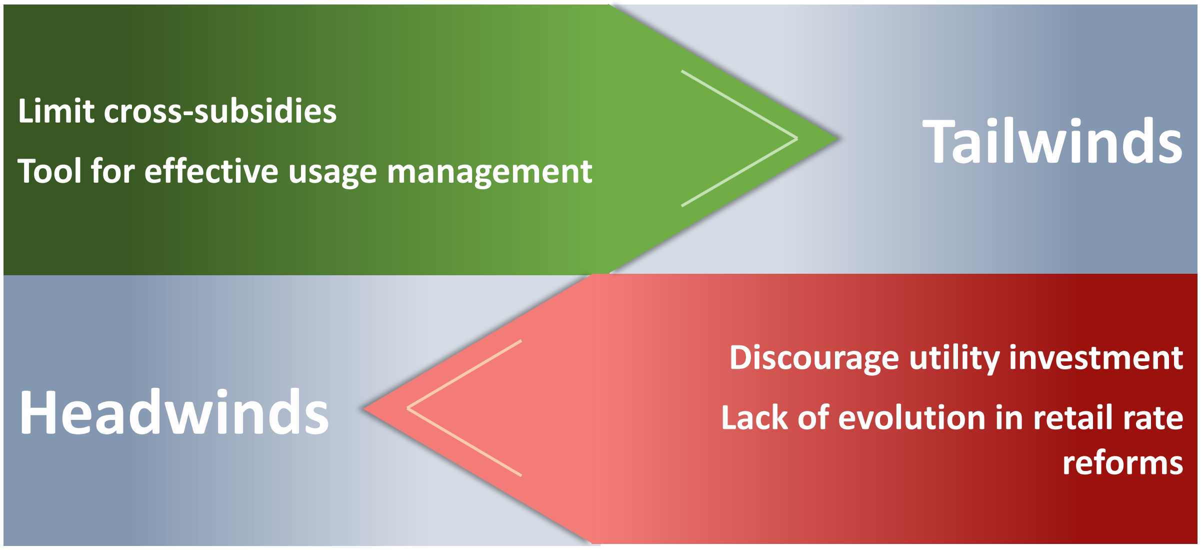

Figure 5. DER Pricing and Program Tailwinds and Headwinds

4.3 New Areas for Pricing, Programs and Procurement

Many of the same trends in technology and policy driving reforms to existing retail rate and DER compensation are advancing new pricing, programs, and procurement for utility grid services and products. These evolutions do not share as clear an historical evolution as retail rates and DER compensation evolutions and are largely entirely new areas of pricing, programs, and procurement.

Most of the examples in the database of new rates and programs advance utility green power and renewable energy[14] towards greater participation, especially focused on low and moderate income customers, and bill crediting mechanisms. Green power, or green tariff, programs have historically sold energy to customers from clean or renewable energy sources often at a premium price. While these green tariff programs continue to grow, albeit at a slow pace (O'Shaughnessy et al., 2016), there are novel features and new program types emerging in several states. The most significant mass market customer program development in the past several years is community solar, in which a utility or third-party develops a solar project and sells the energy output to a group of subscribing customers (O'Shaughnessy et al., 2016). Almost half of U.S. households and businesses lack the ability to host solar PV systems (Feldman et al., 2015). Community solar, or shared solar, programs provide an opportunity for such customers to benefit from solar PV systems. Many community solar programs include a customer bill credit through "virtual net metering" or other DG compensation mechanism. There are currently over a dozen IOU community solar programs in the United States (Trabish, 2017).[15] Consolidated Edison in New York and Arizona Public Service are examples of utilities with shared solar programs targeted specifically at low and moderate income customers who face additional financial barriers to investing in solar PV.

[14] Green power is often considered a subset of renewable energy with the highest environmental benefit.
[15] Sixteen states and Washington, DC enacted community solar laws that include IOUs (Stanton and Kline, 2016).

A second trend in utility rates and programs is the introduction of pricing and program opportunities specifically designed to address periods of over-generation and negative marginal prices, which may occur in the middle-of-the-day when high penetrations of solar PV output peaks. This has been the experience in Arizona and California. Arizona Public Service proposed a “reverse DR” program for commercial and industrial customers to increase load in the middle-of-the-day. Similarly, the California Public Utilities Commission (CPUC) has approved pilot “matinee” pricing programs that offer customers a very low hourly energy rate in the middle-of-the-day to encourage load shifting and load building in periods of over-generation.

A third pricing trend is that utilities are adopting new ways to induce EV charging behaviors that support and provide grid services, where none previously existed at the utility. A number of utilities have implemented or are pursuing TOU pricing pilots for customers with EVs (e.g., investor-owned utilities in California, Rocky Mountain Power in Utah) to see if charging behaviors can be modified by altering the price of electricity paid for charging services based on time-of-day.

Last, utility system planning activities evolved in recent years to take into account more locational granularity with a focus at the distribution feeder level. A number of states utilizing such distribution planning activities are likewise expanding the types of resources under consideration, to include demand-side resources (e.g., New York, California) as non-wires alternatives (NWAs) to distribution infrastructure investments that can provide locational and temporal services necessary to support the grid (Coddington et al., 2017). For example, ConEd’s Brooklyn Queens Demand Management program was established to address needs of a particular substation location on its system (see Text Box). Based on its success, the New York PSC subsequently ordered all of the state’s IOUs to develop their own NWA programs. The New York IOU NWA programs all financially compensate participating customers for reducing load during declared distribution system events but differ in their implementation approaches. For example, some limit participation to only customers in certain geographic locations on their distribution system while others place no such geographic restrictions on participation but pay customers differently based on where they were located on the grid (NYPSC, 2016). Similarly, the California PUC ordered the development of DER resources to serve as NWAs by using a competitive solicitation procurement approach that is technology-neutral (CPUC, 2016c).

Table 3. Sample of New Pricing, Program, and Procurement Approaches

State	Docket/Legislation	Description
AZ	E-01345A-16-0036	Community solar low-income program (Arizona Public Service)
AZ	E-01345A-17-0134	Reverse DR program (Arizona Public Service)
CA	A.14-10-014, A.15-02-009	EV TOU rate for charging pilot (All IOUs)
CA	R.14-10-003	NWA program (All IOUs)
CA	R. 13-12-011	Matinee pricing pilots (SDG&E and SCE)
CO	16A-0055E	Community solar program (Xcel)
IA	AEP-2017-0060	Green pricing tariff (Interstate Power and Light)
GA	40161	Community solar program (Georgia Power)
HI	2015-0412	Demand response grid service tariffs (HECO)
NY	14-E-0302	NWA program (All IOUs)
NY	16-E-0622	Community solar low-income program (Consolidated Edison)
WA	UE-160977	Green pricing tariff (Puget Sound Energy)
UT	16-035-36	EV TOU charging pilot (Rocky Mountain Power)

Within the framework, new retail pricing, programs, and procurement fit within the directional trends of grid services and products as they may promote the buying of energy, capacity, and ancillary services from customers or third-party aggregators (see Figure 6). Only one of the new opportunities in the database includes a trend towards partially unbundled grid services. Specifically, DR program modifications in Hawaii established separate tariffs for capacity, fast frequency response, regulating reserve, and replacement reserve grid services. Examples in the database also include features that are more location-based (e.g., zonal and distribution feeder) than historical pricing, programs, and procurement. A few programs also feature more granular temporal elements (e.g., hourly and sub-hourly). Given the broad range of these evolutions, they are administered by utilities as pricing, programs, and procurement depending on how the grid services and products are provided or acquired.

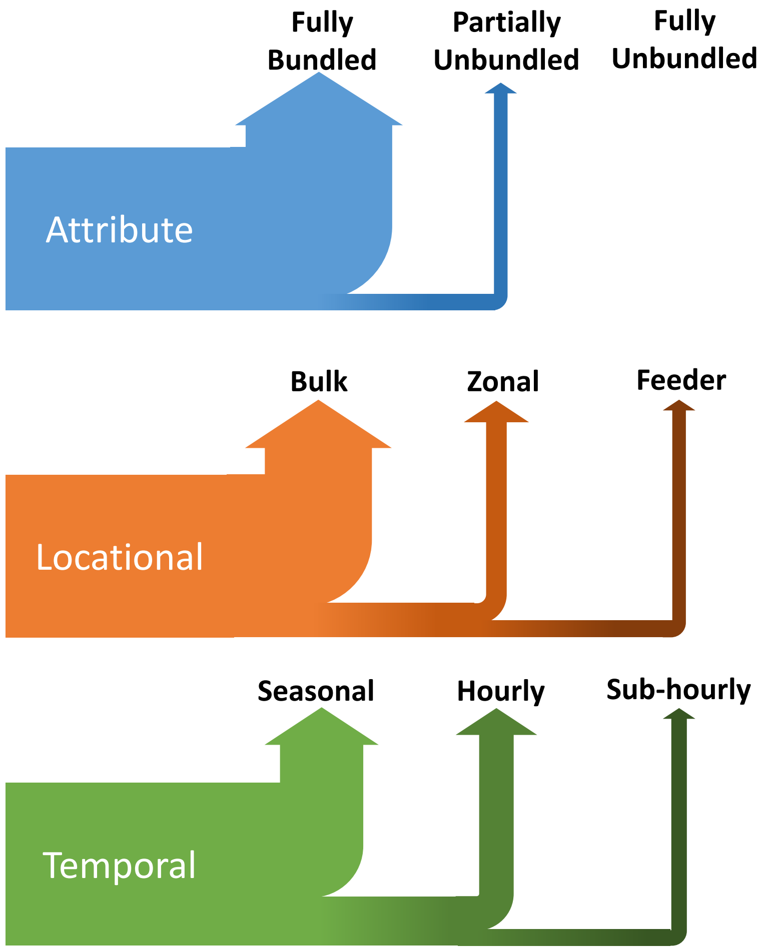

Figure 6. Trends in New Pricing, Programs and Procurement towards Feeder-level Granularity

There are several tailwinds driving the development of new types of utility pricing, programs, and procurement generally applicable across all the examples (see Figure 7). First, new utility offerings are better able to integrate certain public policy objectives into their operations. By innovating in ways that customers want, electric utilities can build better customer relationships and trust (Holt and Galligan, 2017). Second, regulators have historically been supportive of utilities offering innovative pricing and programs that promote load management, load conservation, and DER adoption. By expanding pricing and program offerings in these areas, utility innovation is seen positively by regulators.

Some of the examples in the database increase opportunities for customers to take advantage of new technologies and rates. Green power and community solar programs may be viewed as an alternative to individuals investing in solar that reduces/avoids cost shifting to non-participants (Holt and Galligan, 2017). Community and shared solar programs also enable the utility to better manage its distribution system on a locational and temporal basis that may increase the T&D capacity deferral value (O'Boyle, 2015). Similarly, NWAs can provide solutions to T&D upgrade needs at lower cost and with more environmental and customer benefits (Neme and Grevatt, 2015; Feldman et al., 2017). This creates a structure for more meaningful competition to historic utility monopoly efforts for meeting distribution-system infrastructure requirements to maintain reliability and resiliency.

BROOKLYN-QUEENS DEMAND MANAGEMENT PROGRAM

During the summer of 2014, Consolidated Edison of New York realized that within a few years they would need to add a substation at a cost of $1.2 billion or more in part of their distribution system spanning sections of Brooklyn and Queens that was rapidly growing. The utility sought community ideas on how it could address the problem with NWA solutions that were cheaper for customers. The end result was the Brooklyn Queens Demand Management (BQDM) program that procured EE, DR, and DERs like fuel cells and neighborhood scale solar projects to defer the need for the costly system upgrade (NYPSC,2014)

Headwinds to further development of new retail rates, programs, and procurement approaches relate to utility financial incentives under rate-of-return regulatory models and concerns about the cost-effectiveness of new approaches (see Figure 7). The pursuit of NWA programs and procurement opportunities runs counter to a utility's preference for capital investment (Averch and Johnson, 1962). Utilities have historically avoided pursuing demand-side management efforts, broadly speaking, because they are predicated on deferring the need for future capital investment by reducing system peak, annual energy, or providing the utility with any number of other such services. This "lost future earnings opportunity effect" typically results in utilities seeking some sort of shareholder incentive mechanism to achieve DSM savings goals (Satchwell et al., 2015). This suggests that utilities may be unlikely to pursue NWAs unless they are ordered to do so or receive some sort of opportunity to generate profit from successfully implementing such opportunities. Other technologies like energy storage may prove more cost-effective or beneficial to the system than solar and load shifting, particularly as storage costs continue to decline. Utility-scale solar is more cost effective than community solar when considering economies of scale (Holt and Galligan, 2017). There may also be more efficient and effective ways of dealing with excess renewable energy production than paying customers to consume electricity (e.g., run water pumps during periods of low load and high solar output) (Lazar, 2016b).

Other headwinds may be specific to a single perspective but are, nonetheless, a potential hindrance to further evolution in this area. For example, some people do not want a community solar array sited nearby (i.e., NIMBY) (Holt and Galligan, 2017). Also, city officials may be concerned about safety of storage and integrated NWA systems (Inc., 2017). Finally, utilities' general lack of experience with NWAs and lack of demonstrated equivalence between NWAs and utility distribution and transmission investments may limit their proliferation in the near term (Stanton, 2015b).

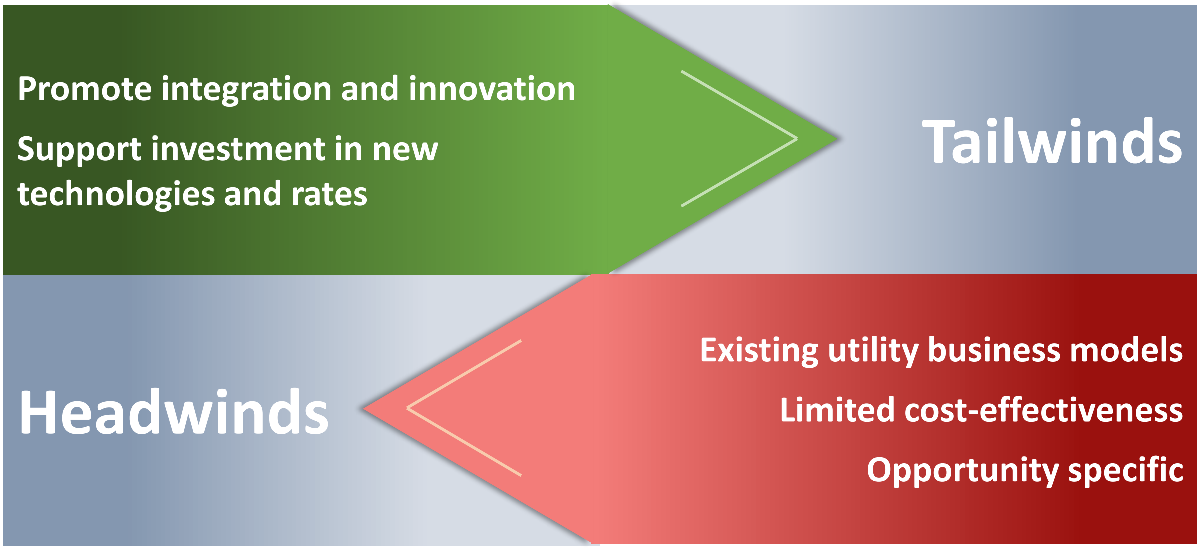

Figure 7. New Pricing, Program, and Procurement Tailwinds and Headwinds

5. Evolution in Market Opportunities

At the onset of the electric industry, increasing customer consumption was key to supporting the electric utility business model. Utilities helped create a market for the light bulb by both selling the product as well as the electricity to power it (ASE, 2013). Subsequent utility efforts to enter new markets or expand existing markets, in some form or another, did not really take off until the 1970s (ASE, 2013). At that time, regulators and policymakers increasingly recognized that electric utilities were in a strong position to greatly expand the market for EE and other load management products. Through a number of federal and state enabling policies, utilities in many states became the entity responsible for administering, if not directly delivering, EE and other load management products (Lazar and Colburn, 2013).

There is a renewed interest in some states in potentially having regulated electric utilities play an integral role in promoting the expansion of new or existing technologies or business opportunities. For example, new forms of electrification, especially of the transportation sector, and DG technologies are readily identified as opportunities where utility support could be instrumental, and possibly necessary, in driving down investment costs in order to achieve state and federal policy goals. Implications from the achievement of such goals may necessitate the promotion of other technologies, like DR or battery storage, that can help better integrate variable generation technologies into the distribution and transmission grids, as well as the bulk power system. In addition, increasing digitalization through phone-based applications and home automation technologies creates new opportunities for regulated electric utilities to better support existing electric customers as well as third-party businesses.

Various states and utilities have proposed or are testing alternative approaches that offer new roles and opportunities for regulated electric utilities. This section discusses the many ways in which this evolution is occurring that supports and/or expands potential market opportunities for regulated electric utilities.

5.1 Utility Asset Ownership

An analysis of the database revealed that the most direct way for regulated electric utilities to promote new markets and expand existing ones is to make investments that enable customers and resources to become market participants (see Table 4). This is particularly true concerning residential and small-commercial solar PV markets and EV markets, where the latter focus has been on charging station infrastructure. Although there has been substantial discussion and interest about these issues over the past several years in the electric industry as a whole, relatively modest regulatory and legislative action has occurred among a number of utilities pursuing or evaluating direct ownership of community solar (e.g., Consolidated Edison, Georgia Power) or EV charging station infrastructure (e.g., Ameren Missouri, Consumers Energy, KCP&L). There has been more limited interest by regulated electric utilities to pursue investments in customer rooftop solar systems (e.g., Arizona Public Service).

Table 4. Sample of Utility Ownership Market Opportunities

State	Docket/Legislation	Description
AZ	E-01345A-16-0036	Customer-scale solar (Arizona Public Service)
AZ	E-01345A-17-0134	EV charging stations
CA	A.14-04-014, A-15-02-009	EV charging stations (PG&E, SDG&E)
FL	20170183	EV charging stations and battery storage sites (Duke Energy Florida)
GA	40161	Community-scale solar (Georgia Power)
KS	16-KCPE-160-MIS	EV charging stations (KCP&L)
MI	U017990	EV charging stations (Consumers Energy)
MO	ET-2016-0246, ER-2016-0285	EV charging stations (Ameren, KCP&L)
NY	16-E-0622	Community-scale solar (Consolidated Edison)

Utility ownership evolutions exhibit a number of features (see Figure 8). The investment efforts that have either been proposed or approved generally authorize the utility to incur 100% of the total investment cost of these technologies. However, the assignment of responsibility for the recovery of the investment cost is split between participating and non-participating customers, varying by technology under consideration. For example, the investment costs for utility-owned or procured battery storage systems are generally considered the responsibility of all customers, since the grid services they provide benefit everyone. As such, the investment costs are recovered via retail electricity rates. In contrast, EV owners who use utility-owned charging stations have been assigned responsibility to repay the utility's investment costs, which typically occurs through charging station rates.

The costs of utility-owned solar systems are typically recovered in one of two ways. First, customers who subscribe to a utility's shared-solar program have generally been responsible for community scale solar investment costs. Second, in the case of low-income customers, the investment cost responsibility is assigned to all customers through existing pricing opportunities for social equity reasons. In both cases, however, the utility receives asset ownership rights after repayment of the investment cost have been made in full.

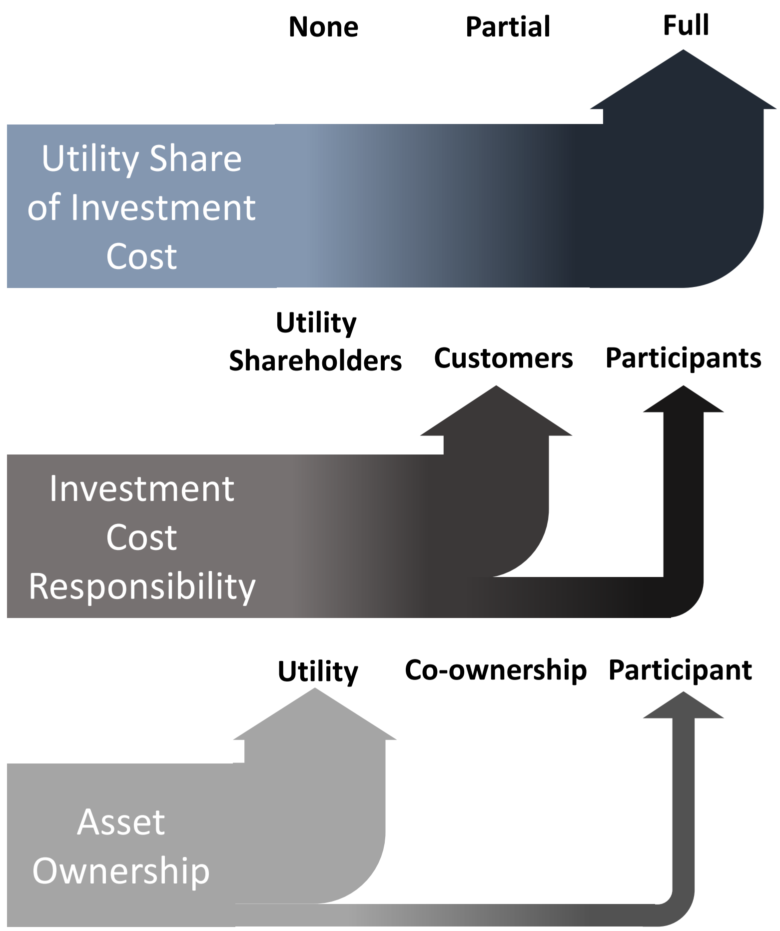

Figure 8. Trends in Utility Asset Investments towards Customer Cost Responsibility and Utility Ownership

Views on the appropriateness of utility investments made with ratepayer money to promote and expand various EV market opportunities vary significantly (see Figure 9). Some stakeholders, including utilities themselves, see a strong role for the monopoly franchise, providing a number of tailwinds to support these evolutions. At their core, electric utilities have a regulatory mandate to serve all customers. This has historically helped to ensure that their service and product offerings reach larger groups of customers than similar efforts by independent third-parties (Blansfield et al., 2017). But this also meant that electric utilities may enter markets dominated by third-party providers who are underserving certain communities. For example, where third-parties have been the exclusive entity participating in the residential solar market, low and moderate income households have generally been underserved due to a myriad of market barriers (Paulos, 2017). Utilities have proposed to fill this gap by investing in community solar (e.g., GAPSC, 2017) or leasing customer rooftops for utility-owned solar systems (e.g., ACC, 2017).

Where private entities have failed to sufficiently invest in enabling EV infrastructure or supply chains, monopoly electric utilities may be uniquely positioned to facilitate the development of a competitive market(CPUC, 2014; NYPSC, 2015; CDG Stakeholders, 2017) or to directly provision or procure grid services and products where no competitive market currently exists (NYPSC, 2015; Blansfield et al., 2017). For example, customer-funded support of EV charging infrastructure can create market readiness for eventual uptake of EVs but fill in the gap until private markets see such investments as viable (NYSERDA, 2015). Utility investment and ownership of assets through demonstration partnerships with third party EV charging companies can likewise accelerate the development of sustainable business models (NYPSC, 2015).

EV CHARGING STATIONS AT CUSTOMER HOST SITES

In August of 2017, Duke Energy Florida (DEF) filed a settlement agreement with the Florida Public Service Commission in their general rate case. It included authorization to incur up to $8 million plus reasonable operating and maintenance expenses to deploy 530 EV supply equipment (i.e., charging stations) at customer hosts sites over a five year period. DEF will defer the recovery of all incurred capital costs and operating expenses to a regulatory asset which can earn the utility's authorized rate of return. Revenues generated from charging services at these stations will offset costs in the regulatory asset.

Importantly, utility investment in EV infrastructure may create new revenue and profit generating opportunities for electric utilities that mitigate some or all of the potential financial impacts of declining load (Satchwell et al., 2014). To a somewhat lesser degree, the electric utility's ability to procure lower cost capital may further provide electric utilities with a competitive advantage over third-party EV charging station providers (Blansfield et al., 2017), creating opportunities to meet public policy goals at lower total overall cost. Finally, electric utilities know their systems better than anyone else. This may enable them to deliver products in a more organized and systematic way that better supports the grid to meet its needs on a geographical and temporal basis (NYPSC, 2015; Blansfield et al., 2017).

These utility EV charging infrastructure ownership opportunities also face a number of headwinds raised by regulators and stakeholders concerned about adverse impacts on competitive markets and a risk of undermining market development (see Figure 9). Utility ownership may discourage potential investment from competitive providers due to utility access to less expensive capital, access to data for more personalized marketing, and brand recognition with customers (NYPSC, 2015; MIPSC, 2016). Unrestricted, utilities may make investments in areas where private parties are already competing for business. Although this may increase competition in narrowly defined EV charging markets, it likely avoids addressing larger and more structural market deficiencies, like issues of underserved markets, where the utility role would be seemingly more appropriate (CPUC, 2016b).

A number of stakeholders have raised concerns about adverse impacts on customers when utilities make investments to promote market expansion, which have created further headwinds for the pursuit of utility asset ownership opportunities. EV charging technology is evolving rapidly. Utility investment in one type of charging technology (e.g., direct current (DC) fast chargers) may create a greater likelihood of stranded assets and may pursue options where benefits are overly speculative (CPUC, 2016b). Utility ownership (e.g., community solar projects) may result in policy objectives (e.g., increased PV penetration) being met at higher cost (NYPSC, 2015). Furthermore, utility investments may not meet the legal standard for what qualifies as "electric plant" (MOPSC, 2017) under existing statutory definitions, thereby limiting the role utilities can play in fostering market development to non-investment activities.

Last, some contend that electric utilities may not even be the right entity to support market growth. In some cases, it may be problematic to assume that the utility can successfully expand into new and existing market opportunities, given its limited successful experience with innovation vis-à-vis private enterprise which must survive in a competitive market by being innovative (NYPSC, 2015).

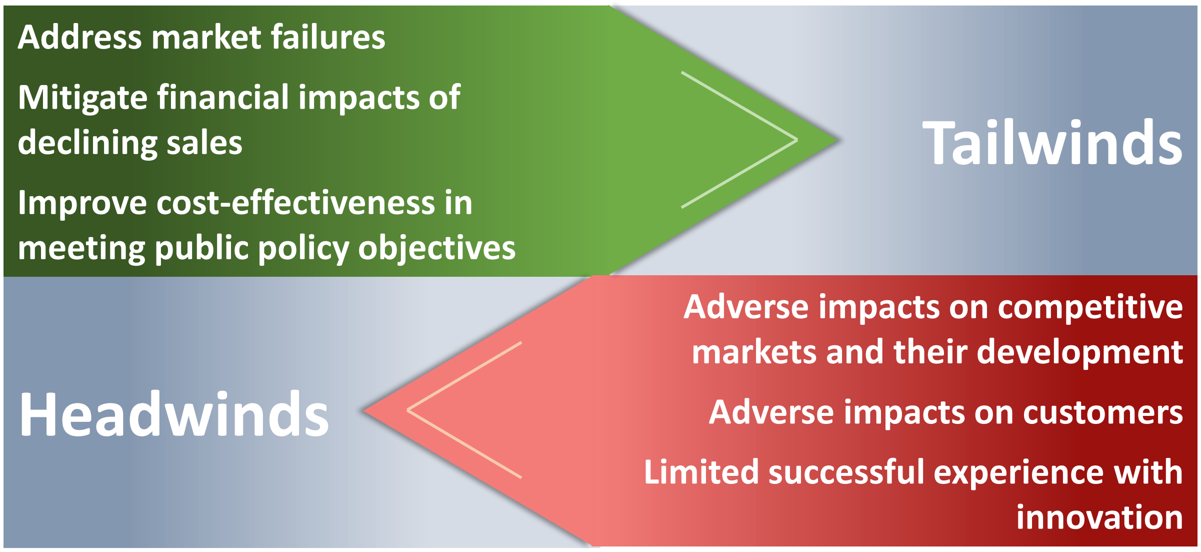

Figure 9. Utility Asset Ownership Tailwinds and Headwinds

5.2 Utility Financial Support

Given the numerous concerns raised about direct investment and ownership of assets by regulated electric utilities to promote market development, many regulators and policymakers are seeking alternative and less direct roles for the utility in some markets. In particular, regulators and utilities have taken two general approaches for reducing the barrier to investment by lowering the up-front capital costs (see Table 5). First, a number of utilities have been authorized to offer direct financial rebates on a number of consumer products that support renewables integration efforts (e.g., Green Mountain Power in Vermont, all New York investor-owned utilities) and promote electrification of the grid through increased adoption of more efficient electrified end-uses, like air-source heat pumps (e.g., Green Mountain Power in Vermont) and various types of EV chargers (e.g., PEPCO, Consumers Energy).[16] Second, regulators and policymakers have sought to reduce the complexity and cost of installing EV charging stations by allowing utilities to invest in supporting and enabling grid-side infrastructure upgrades[17] (e.g., PEPCO, AEP Ohio, Consumers Energy, and PG&E).

[16] A number of states (e.g., California, Colorado, Illinois, New York, and Washington) and the District of Columbia have similar low-income solar rebate programs administered by non-utility entities (Paulos, 2017).
[17] i.e., EV supply / "make ready" infrastructure

Table 5. Sample of Utility Financial Support Market Opportunities

State	Docket/Legislation	Description
CA	A-15-02-009	Investment in EV supply infrastructure (PG&E)
DC	FC1143	Rebates for EV charging equipment and investment in EV supply infrastructure (PEPCO)
MI	U017990	Rebates for EV charging equipment and investment in EV supply infrastructure (Consumers Energy)
NY	14-E-0318	Rebates for energy efficient or controllable consumer products via online marketplace (all IOUs) and EV connected devices (Consolidated Edison)
OH	16-1852-EL-SSO	Rebates for EV charging equipment and site development (AEP Ohio)
VT	17-3122-INV	Rebates for energy efficient or controllable consumer products via online marketplace (Green Mountain Power)

The market opportunities in utility financial support have common features (see Figure 10). Where the utility is pursuing opportunities to make capital investments in support of market development, it is seeking to cover only a partial share of the total project cost. Specifically, instead of incurring 100% of the capital expenses for an EV charging station, the costs are now split between the utility, that is focusing on the grid-side of the station by limiting their investment to “make ready” infrastructure, and the station developer, that incurs the balance of the project capital requirement. Concerning utility-provided direct financial rebates on consumer products or EV charging/connected equipment, capital investment costs are shared between the utility (e.g., rebate) and customer/third-party (remaining costs). For both types of utility financial support opportunities, customers as a whole are responsible for covering the costs incurred by the utility, who eventually retains ownership of whatever asset is being deployed (e.g., Green Mountain Power leased heat-pumps), with the exception of a subset of consumer products (e.g., programmable communicating thermostats and other consumer electronics offered by New York State investor-owned utilities via their online marketplaces).

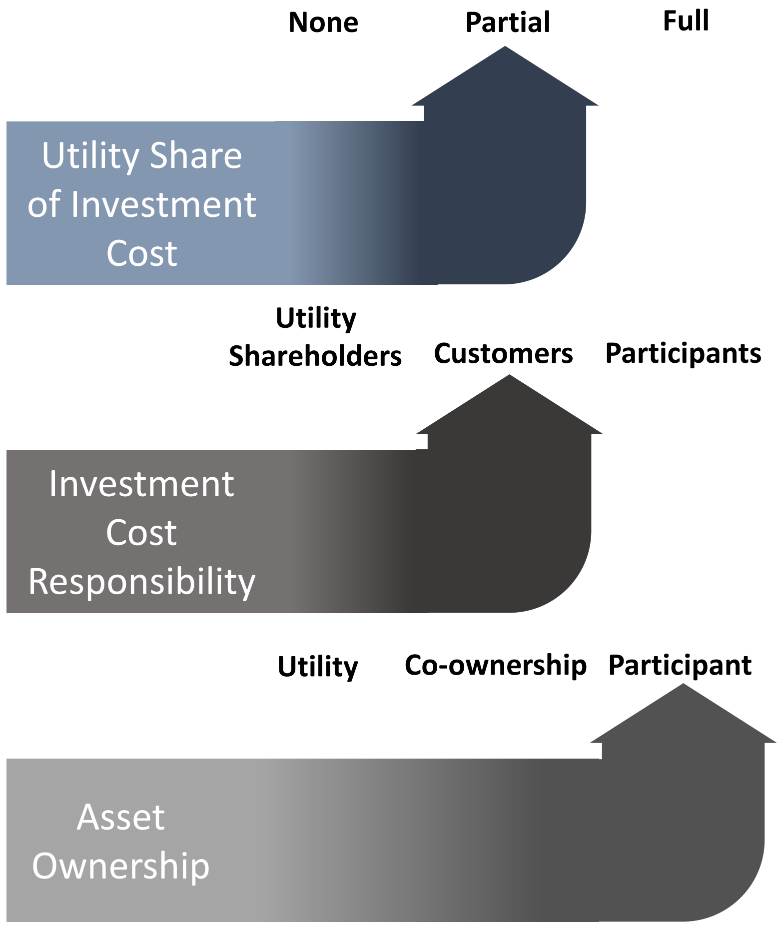

Figure 10. Trends in Utility Financial Support towards Customer Cost Responsibility and Participant Asset Ownership

A number of arguments have been put forth to support these proposals (see Figure 11). Several echo tailwinds observed in support of direct utility investment discussed in Section 5.1. By limiting utility involvement to subsidies and other efforts to drive down up-front investment costs, broader competitive markets can be protected (NYSERDA, 2015) while facilitating development in more difficult markets (CPUC, 2016a). Customer-funded support (e.g., site preparation of EV charging infrastructure) can create market readiness for the anticipated uptake in demand but fill in the gap until private markets see such investments as viable (NYSERDA, 2015). Some stakeholders see utilities as uniquely qualified to readily assess the costs and benefits of more precisely targeting market development at specific locations through rebates and other cost subsidies (NYSERDA, 2015). Other stakeholders contend that providing financial incentives for products that align well with utility controllability objectives for different end-uses (e.g., EV chargers, consumer products) are worth pursuing, provided it is cost-effective (NYSERDA, 2015).

TESLA POWERWALL 2 LEASING PROGRAM

In May of 2017, Green Mountain Power announced a partnership with Tesla to offer customers in Vermont the ability to lease a Powerwall 2 system (GMP, 2017). The utility committed to installing up to 2,000 Powerwall batteries to homeowners for either $15/month or a one-time fee of $1,500. Customers receive between 8-12 hours of backup power to their home for the next 10 years, while GMP may use the batteries during peak energy times to provide bulk-power system grid services that support reliability.

Despite this more limited role for utilities, some stakeholders still have a number of unresolved concerns that are acting as headwinds to these evolutions (see Figure 11). If approval for rebates and other financial incentives must be predicated on a cost-effectiveness test, the accuracy of such quantitative assessments can be challenging in an infant industry where benefits may be speculative (CPUC, 2016a). It can also be difficult to judge whether or not the size of the rebate is robust enough to meaningfully affect adoption rates but not too generous such that it promotes free-riders (CPUC, 2016a). Some stakeholders further contend that utility financial support of any kind (e.g., "make ready" EV infrastructure) can be harmful to competition and market development (CPUC, 2016a).

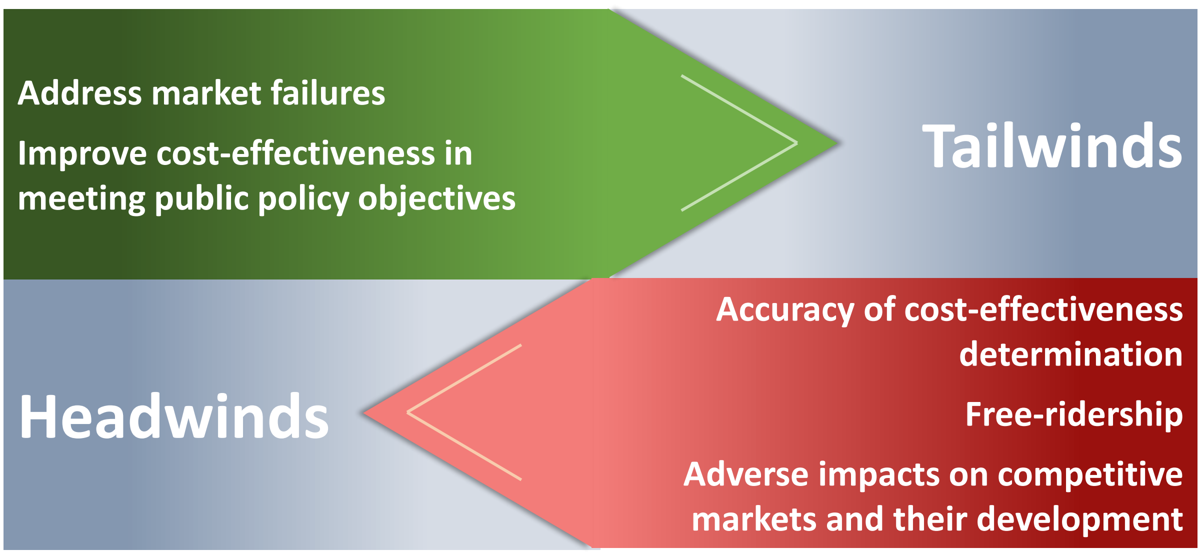

Figure 11. Utility Financial Support Tailwinds and Headwinds

5.3 New Market Opportunities

Over the past several years, a number of regulators, policymakers, and utilities looked beyond the traditional boundaries of the regulated electric utility market of delivering grid services and products (see Table 6). Among other things, they see opportunities for utilities to leverage existing or planned grid modernization investments for the purposes of creating new grid services and products which enable greater customer engagement and support third-party value-added offerings (Blansfield et al., 2017). Distribution system sensors, advanced meters, and a myriad of connected devices are a few examples of technologies gathering data and sending it back to electric utilities. A small number of regulatory commissions are promoting utility data as service opportunities, where utilities sell their data, either in its original or aggregated form, to third parties who subsequently use it to market their own grid services and products to end-use customers (e.g., Illinois, Massachusetts, New York, New Jersey). Recent efforts to promote easy and secure access to energy usage data (i.e., Green Button) created market opportunities for utilities to offer their own software applications that package this information to better engage consumers in energy savings opportunities (e.g., DTE Energy's Insight App) or promote those of third parties (e.g., Duke Energy and American Electric Power are market-testing Tendril's MyHome, WattzOn integrates with PG&E ShareMyData, EPA Energy Star's Portfolio Manager works with several electric investor-owned utilities including Avista in Idaho). There has also been considerable interest in having utilities make detailed or aggregated system data publicly available, like hosting capacity analyses (e.g., California and New York investor-owned utilities) (IREC, 2017).

Table 6. Sample of New Market Opportunities

State	Docket/Legislation	Description
CA	N/A	Customer engagement and data accessible via smart phone app (PG&E); System Data-As-A-Service market opportunity (all IOUs)
ID	N/A	Customer benchmarking data via EPA Energy Star's Portfolio Manager (Avista)
IL	13-0506	Customer Data-As-A-Service market opportunity (All IOUs)
IN	N/A	Customer engagement and data accessible via smart phone app (AEP)
MA	N/A	Customer Data-As-A-Service market opportunity (All IOUs)
MI	N/A	Customer engagement and data accessible via smart phone app (DTE Energy, AEP)
NJ	N/A	Customer Data-As-A-Service market opportunity (All IOUs)
OH	N/A	Customer engagement and data accessible via smart phone app
NY	14-M-0101	Customer and System Data-As-A-Service market opportunity (All IOUs)

The features associated with these new market opportunities are evolving and details are limited, since very few have been implemented. However, in those few jurisdictions which have pursued them, the framework can be used to understand how they have been implemented (see Figure 12). Because these opportunities reflect utility efforts to sell a service and receive payment for it, they would qualify as pricing opportunities under the framework. Utilities have clearly stated their desire for full and complete cost recovery for expenditures made to support and enable these new data-driven market opportunities. Where utility data-as-a-service exists, regulators have expressed differing opinions on who should be responsible for cost repayment. For example, according to comments filed by Good Energy, a Community Choice Aggregator, utilities in Massachusetts and New Jersey assign 100% of the costs of Community Choice Aggregation (CCA) data services to customers as a way to promote this nascent market (Good Energy, 2017). However, regulators in New York directed the state's IOUs to share the cost of such data efforts evenly between customers and CCAs (NYPSC, 2017a). Alternatively, entities who receive more customized data services from Commonwealth Edison appear to be responsible for recovering 100% of the costs (see text box). Utilities who invest in information technology (IT) infrastructure to directly provide these data services appear able to ultimately own the technology – although some may want to pursue outside vendors who would perform some/all of the data analysis.

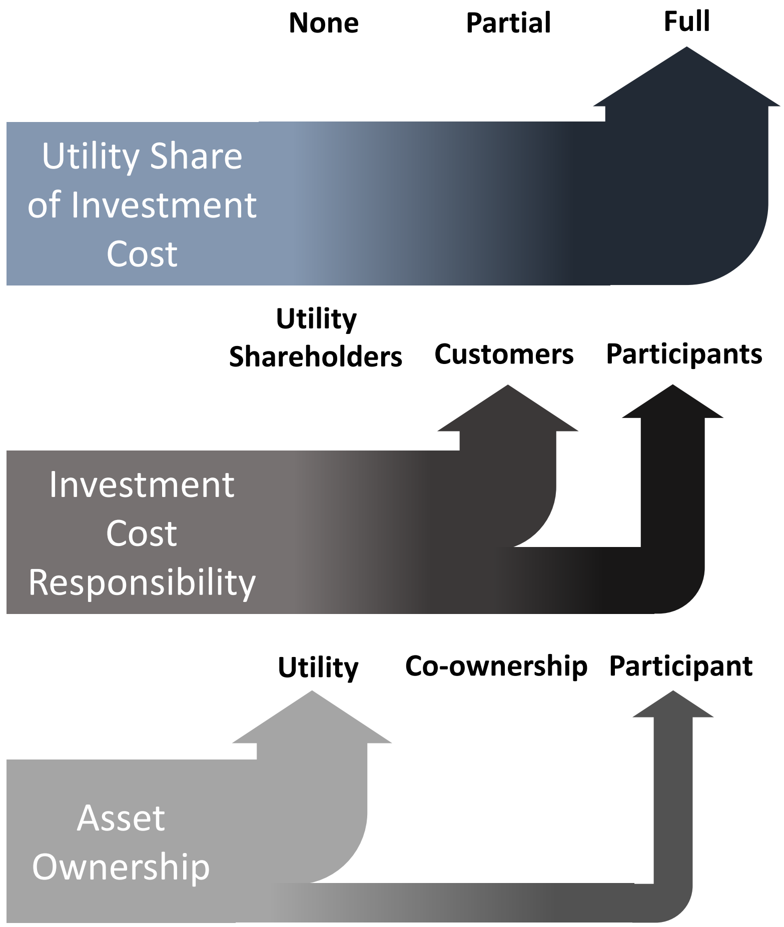

Figure 12. Trends in New Market Opportunities towards Customer and Participant Cost Responsibility

A number of positions have been argued supporting efforts to embark on these new market opportunities that differ based on the type of data under review (see Figure 13).[18] Regarding access to customer-level data, the intent is that customers would become more engaged in their energy consumption decisions (NYPSC, 2015). Businesses would likewise be able to better inform customers about choices for energy management opportunities (TechNet et al., 2016) and better identify customers best suited for their product and service offerings (e.g., DERs) (Joint Utilities, 2016). If system data is made more readily available, some expect it could improve grid design and operation by

[18] Utilities are not necessarily universally supportive of these new opportunities. For example, Commonwealth Edison has actively pursued opportunities to extract value from its grid modernization investments that include AMI. Alternatively, regulators in New York are the ones championing these opportunities, with the various New York investor-owned utilities taking a more cautious and deliberate approach to them.

driving more cost-effective, reliable and efficient outcomes as well as by providing greater accountability through increased transparency (TechNet et al., 2016). When joined with customer data, organizations (e.g., DER providers) can better assess where to market and locate their grid services and products to maximize value extraction (Joint Utilities, 2016). Furthermore, lack of robust system data may undermine market development and allow utilities to exert undue market power (NYPSC, 2015).

ANONYMOUS DATA SERVICE

Commonwealth Edison is looking to convert the wealth of energy data generated by its investment in AMI into product and service offerings by third-parties that can help its customers save energy and money. The utility offers anonymized 30-minute interval data clustered with no fewer than 15 customers where any individual included customer must have usage that is no more than 15% of the group's total usage. This Anonymous Data Service is offered for $900/month for five-digit zip code-based data. However, the utility also offers custom data compilations for $145/hour.

Stakeholders, regulators and utilities have identified a number of concerns that act as headwinds for the pursuit of these new market opportunities (see Figure 13). In a general sense, there are concerns about how broadly to share data, who is responsible for setting qualifications for access, and how to ensure entities accessing it have the necessary credentials to address cybersecurity and privacy concerns (TechNet et al., 2016). The current lack of standards concerning data granularity and data sharing processes may stymy or at least hinder broader industry efforts to find applications for this data (AEE, 2014). The time and resources to gather, organize, clean and implement widespread data access may be significant, which will require detailed implementation, investment, and cost recovery plans before utilities are likely to embark on such efforts (Joint Utilities, 2016).

Privacy issues are the major headwind for evolutions regarding customer data. Analysis of meter data can reveal basic occupancy trends, consumption patterns and even disaggregation of certain end-uses. However, increasing the level of aggregation to ensure privacy may reduce transparency of utility operations, reduce granularity for siting and marketing efforts, and produce data of questionable accuracy (TechNet et al., 2016). With respect to grid data, the issues of security (e.g., enable attacks on critical infrastructure) (TechNet et al., 2016) and accessibility (e.g., lack of unanimity on data access issues) (NYPSC, 2015) appear to be two major concerns.

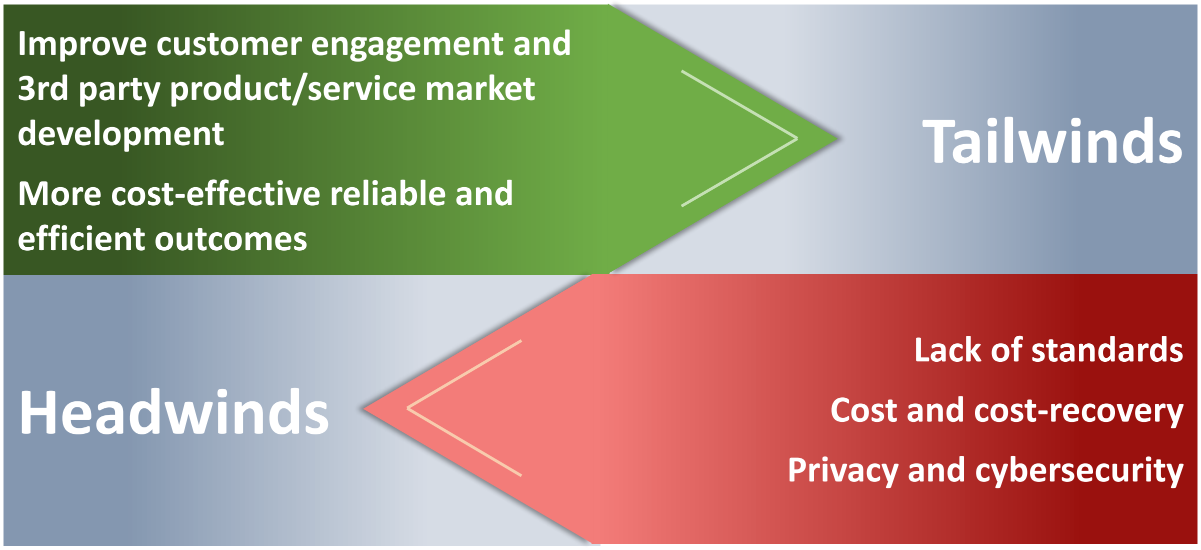

Figure 13. New Market Opportunity Tailwinds and Headwinds

6. Implications for Regulators and Policymakers

The report identifies major evolutions in grid services, products, and market opportunities drawn from recent regulatory cases and state legislation driven by the myriad technological, economic, and policy shifts occurring in the electric utility industry. Numerous evolutions were identified moving incrementally across the features in the framework (e.g., retail rate reforms moving from annual to hourly pricing, DG compensation reforms moving from fully bundled to partially unbundled attributes). A much smaller number of evolutions moved towards more distant points on the continuums: fully unbundled attributes, sub-hourly time-scale, and feeder location. Regulators and policymakers may find the features of evolution in the report's framework (i.e., attribute, locational, temporal, utility share of investment cost, investment cost responsibility, and asset ownership) useful for evaluating pricing, program, or procurement reforms.

In the discussion of tailwinds and headwinds, there are several common policy issues and stakeholder concerns. First, concerns about utility financial viability and business models in a future of low load growth and increasing DG deployment drive interest in DER compensation reform and also a number of market opportunities that create possibilities for new capital investment and/or new revenue streams for the utility. Second, customer fairness and equity concerns continue to be a top priority for regulators, especially as they consider retail rate and DER compensation reforms. In some cases, regulators are creating new customer classes based on whether they have DG systems. Regulators, policymakers, and utilities are also increasingly attuned to low- and moderate-income customers and ensuring fair and equal access and opportunity for them to take advantage of new technologies, pricing, and programs. Third, there are differing perspectives on the appropriate role(s) for utilities in developing nascent markets and technologies that could serve as tailwinds or headwinds for new market opportunities. Expanding utility markets beyond traditional grid services and products act either as tailwinds or headwinds — aiding or impairing market development.

Two important and related themes emerge from the report suggesting implications for regulators and policymakers:

- First, there is **increasing competition** to serve the energy generation needs of retail customers. Some reforms are eroding the exclusivity of the utility franchise by enabling and promoting the myriad opportunities to supplant some or all of the services and products the utility historically provided. For example, regulatory requirements for utilities to pursue NWA program and procurement opportunities pit utility investments against customer investments. In contrast, other reforms support the utility's exclusivity by limiting competition for these historical utility products and services, either directly by excluding or supplanting opportunities for third parties (e.g., utility owned community or customer-scale solar) or indirectly by reducing the financial viability of their offerings (e.g., NEM compensation reforms). Regulatory decisions affecting the firmness of the utility franchise boundaries weight the risk that may entail from its erosion (e.g., reduced reliability, reduced utility financial viability) with the reward that may come with increased competition (e.g., increased customer engagement, decreased long-term costs to customers, enhanced market development), all of which carry important political, market, and legal implications that are being dealt with differently across the country.

- Second, states, utilities, regulators, and policymakers are recognizing opportunities for **greater innovation** within and outside the electric industry. A number of electric utilities are developing novel financial support mechanisms for the adoption of DERs, as well as creating new market opportunities that provide data services to support third-party commercial enterprises' efforts to reach customers more efficiently and effectively. Some states see utilities as able to play a critical role in promoting or supporting innovation in other industries, whereas others believe the risks are too great with utility involvement. For example, regulators in California authorized limited utility investments under rate-of-return regulation in EV charging infrastructure as a way to promote greater EV ownership and usage; whereas regulators in Kansas rejected a utility proposal to ratebase EV charging infrastructure citing several uncertainties and a misalignment with regulatory goals of "sufficient and efficient service".

The examples from the database suggest regulatory decisions increasingly have substantial implications for competition and innovation; so regulators should formulate clear and consistent policy goals around these two issues to help guide their decision making in the future.

Although not covered in this report, there are several trends occurring more broadly in the electric utility industry that are related to grid services, products, and market opportunities. First, utilities are beginning to pursue reforms in distribution system planning due to grid reliability concerns presented by deployment of DERs. Such reforms suggest opportunities for advancements in pricing and programs incorporating locational granularity (see Homer et al., 2017). Second, efforts to reform utility regulatory and business models may alter the roles and responsibilities for utilities in delivering grid services and products (see Satchwell et al., 2015). Rhode Island's Power Sector Transformation initiative is considering how to change regulated electric utility regulatory and business models in order to pursue novel reforms (e.g., share the cost burden of advanced metering through innovative partnerships) intended to animate markets for grid services and products (RI Division of Public Utilities & Carriers et al., 2017). Third, a number of broader trends suggest changing utility and customer economics impacting deployment of DERs, including Federal and state tax incentives for accelerated depreciation, tax credits for renewable energy, rebates for EVs, and other trends in customer-end uses, load shapes, and customer behavior.

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