

Transactive Energy Models

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Principal Authors

Ed Cazalet
Paul De Martini
Jeffrey Price
Eric Woychik
John Caldwell

1. Background	3
1) Introduction	3
2) Transactive Energy Defined	3
3) Distributed Energy Resources	4
4) Drivers of Transactive Energy	9
2. Transactive Energy Market Structures	12
1) Introduction	12
2) A Foundation for Comparison of TE Market Structures	14
3) Two Alternative Market Retail Structures	16
4) Comparisons of the Two Alternative Market Retail Structures	29
3. Business Models for Transactive Energy	32
1) Current Electricity Business Models	32
2) Business Models for Future Markets	36
3) How Business Models Will Change	39
4. Transactive Energy Models Overseas	40
1) Denmark	40
2) Canada	42
3) Japan	42
4) Germany	43
5) Australia	43
5. Conclusions and Next Steps	44

Chapter 1: Background¹

1. Introduction

A large number of organizations – both public and private – are now engaged in rethinking the design of the American electricity grid. Scores of white papers have been written on the subject, and a number of state legislative and regulatory bodies are actively promoting a new paradigm for electricity service. While there are differences in the details, a general model is emerging which is centered on the concept of a “transactive” electricity grid, in which traditional customers will be more actively engaged in both consuming and producing electricity, and new entities will adopt roles of varying importance in providing or managing services on the electrical grid. The future role of the electric utility is generally seen as shifting from a provider of electricity to a provider of electricity delivery services and a facilitator of transactions and operations on the grid.

This paper will examine this evolving vision, beginning with a general overview and appraisal of its underlying drivers, and then moving on to a description of two alternative transactive models that are emerging as candidates for putting the vision into operational practice. Because any complex system involving buyers and sellers requires suitable incentives to ensure that those business entities required to make the system work have an incentive to do so, the paper will also discuss various business models that might serve this end.

The paper will also briefly discuss similar initiatives taking place in other countries, and conclude with an assessment of the transactive electricity concept, along with some cautionary remarks about how a transition to this system should occur.

This is Part I of a larger work discussing all aspects of the transactive energy phenomenon. Part II will focus on legislative and regulatory models that could support the evolution and implementation of a transactive energy system.

2. Transactive Energy Defined

What is “transactive energy”? The GridWise® Architecture Council defines it as:

A system of economic and control mechanisms that allows the dynamic balance of supply and demand across the entire electrical infrastructure using value as a key operational parameter.

¹ The purpose of this paper is to describe important trends and phenomena impacting the electricity industry. It is not intended as an advocacy piece, and any views or opinions expressed do not necessarily represent those of the organizations with which these authors are affiliated, or the organizations’ members.

The Transactive Energy Association defines it this way:

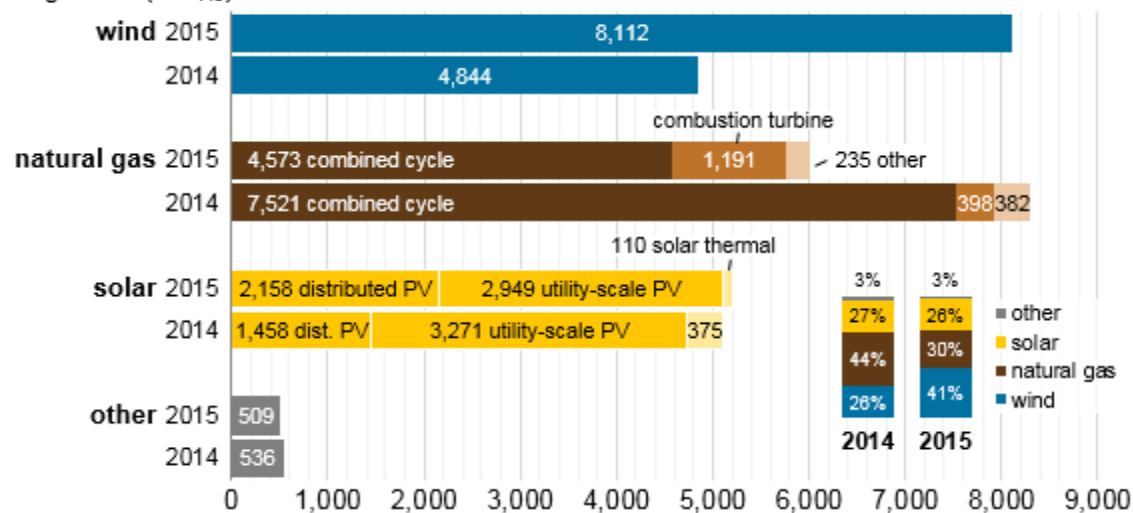
Transactive Energy engages customers and suppliers as participants in decentralized markets for energy transactions that strive towards the three goals of economic efficiency, reliability, and environmental enhancement.

What is common to both of these definitions is the idea that energy will be efficiently distributed from suppliers to consumers through some form of valuation mechanism. The second definition more explicitly identifies markets as the means by which this valuation will occur, and also explicitly notes the implication that this will entail a decentralized system, characterized by multiple buyers and sellers. There is an implication, too, in the second definition that the reason for adopting a transactive energy system is not solely or necessarily because this will produce a more effective, efficient manner of providing reliable electricity service, but also because it will serve the quite distinct goal of “environmental enhancement”. And there is an implication in both definitions that there is a contrast between this system and the ones presently in place for delivering energy – specifically electricity – which are characterized by regulated utilities that play a central role in managing service and delivery. The question that follows is why alternatives to the present system, such as transactive energy, are being considered and in fact actively explored. The answer lies in an examination of what factors are creating the perceived need to engage in this exploration, and principal among these is the presence of distributed energy resources.

3. Distributed Energy Resources

Any discussion of transactive energy must begin with distributed energy resources: the sources of electricity supply or related services, such as storage, that can be owned and operated by third parties, including entities who are receiving electricity service from their local utility. Without these, there would be nothing to engage in transactions with, aside from adjusting one’s own electricity demand in response to time-varying prices set by the utility. And it is only their growing presence on the grid that will make it necessary to consider a departure from the traditional method of managing electricity service at the distribution level. Presently, the overall saturation level of distributed energy resources is still relatively low, exceeding 1% of total generation capacity in only about one-fourth of all states. (Hawaii is the state with the highest current level of DER penetration, at just over 12% of total capacity.) But their presence is growing and is doing so at an increasing rate: According to the Energy Information Administration, distributed solar PV accounted for 11% of total new electricity generation capacity added in 2015; up from 8% of total capacity additions the year before. There are a number of drivers responsible for this phenomenon.

U.S. electric generation capacity additions, 2015 vs. 2014
megawatts (MW_{AC})



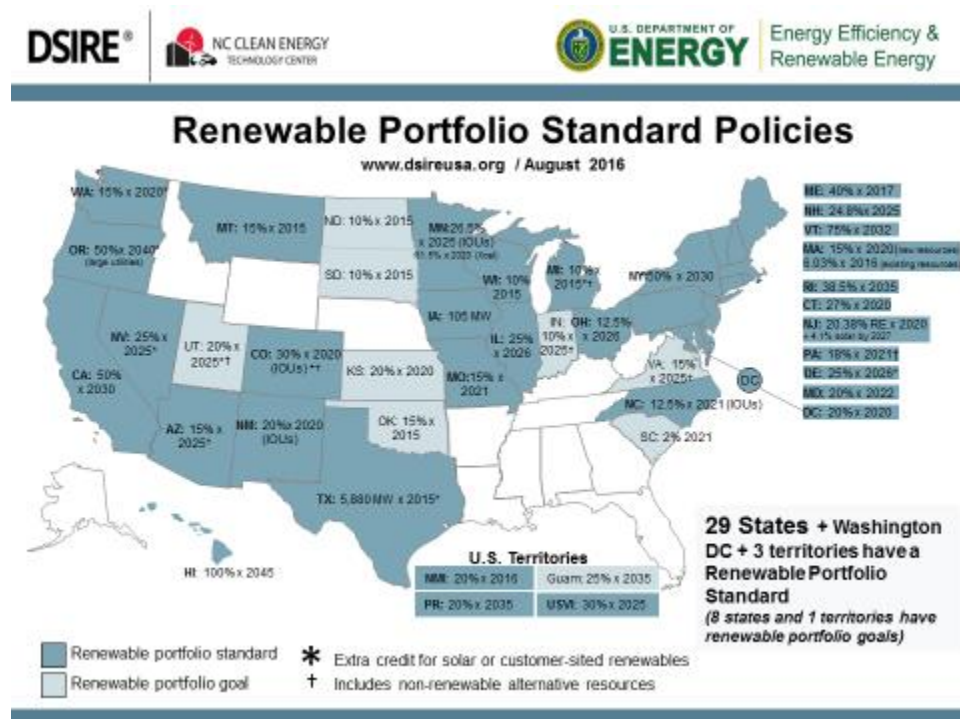
One factor that has contributed to the interest in distributed energy resources is a growing concern about reliability. According to a report published by *Inside Energy*², from 2000 to 2014, the 5-year annual average electricity outage rate doubled every five years, and during that time period, there were 19 weather-related outages (eight due to hurricanes) that affected more than one-million customers. The report attributes this significant growth to aging infrastructure, increased population density, and an increase in extreme weather events. Similarly, a study done by Lawrence Berkeley National Laboratory³ found an average annual increase of 10% in the duration of electricity outages from 2000 to 2012, and also that events related to severe weather was a principal driver for this trend. In 2012, for example, Hurricane Sandy left more than one million customers without power for over a week. While distributed energy resources such as rooftop solar panels cannot in and of themselves provide protection against extended power disruptions, these resources are commonly included in microgrids, which have become increasingly popular as a means of ensuring resiliency of electricity supply. Microgrids were originally embraced mainly by military installations for this purpose, but in recent years have become increasingly popular with commercial and industrial customers, campus facilities such as universities and hospitals, and even residential communities. Their growth in recent years has been phenomenal: According to a quarterly report by Navigant which tracks microgrid projects, the total generating capacity for all microgrids in the U.S. that were either in operation or under development in the fourth quarter of 2012 was just over 2,000 MW, but as of the second quarter of 2016, total capacity has nearly tripled to about 5,800 MW.

Another factor contributing to the rise of distributed energy resources is the existence of policies at the state and federal level that promote the development of clean energy. Twenty-nine states and the

² Jordan Wirfs-Brock, "Power Outages on the Rise Across the U.S.", August 18, 2014, Inside Energy, <http://insideenergy.org/2014/08/18/power-outages-on-the-rise-across-the-u-s/>

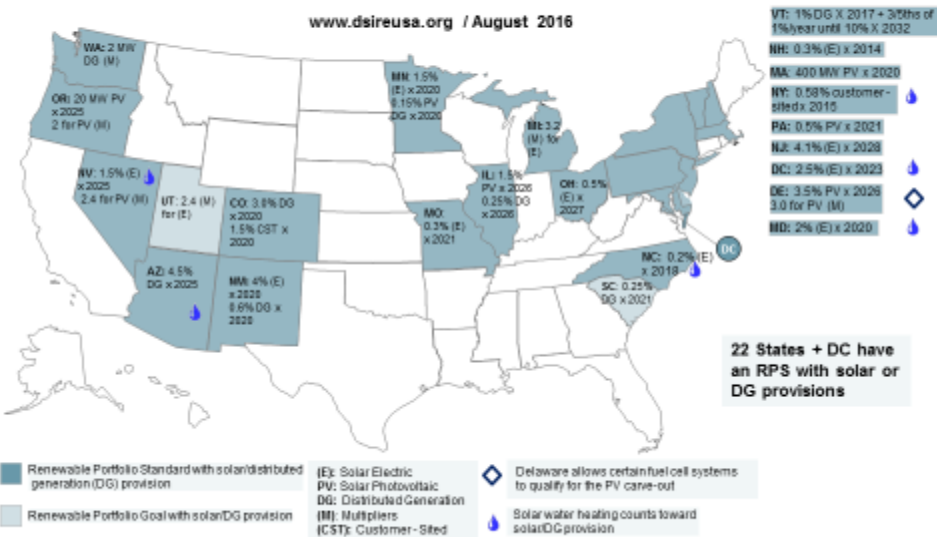
³ Larson, LaCommare, Eto, and Sweeney, "Assessing Changes in the Reliability of the U.S. Electric Power System", August 2015, Lawrence Berkeley National Laboratory

District of Columbia currently have renewable portfolio standards in place that set percentage targets and timelines for non-carbon-emitting electricity sources. These targets generally range from 10% to 30% and specify time frames of 5 to 10 years, but others set more ambitious goals and/or longer time frames. California, for example, is targeting 50% of electricity production from renewable resources by 2030, and Hawaii has set a 100% renewables goal for 2045. Twenty-two states and the District of Columbia actually have RPS policies with explicit solar and/or distributed generation provisions. Some regions in the United States are considering, or have already adopted, “cap-and-trade” programs which limit carbon emissions through the use of carbon allowances that can be bought and sold between electricity providers. While these emissions trading systems are targeted to large-scale carbon-emitters, the implicit value on CO₂ emissions reductions that result from their operation could potentially be monetized in a way that provides benefits to smaller-scale providers of clean electricity. Similarly, when and if the EPA’s Clean Power Plan is implemented, a tangible value to CO₂ emissions reductions will result which could potentially be captured by providers of clean distributed energy resources, if the method of compensation for these resources takes into account the benefit of these reduced emissions.



Renewable Portfolio Standards (RPS) with Solar or Distributed Generation Provisions

www.dsireusa.org / August 2016

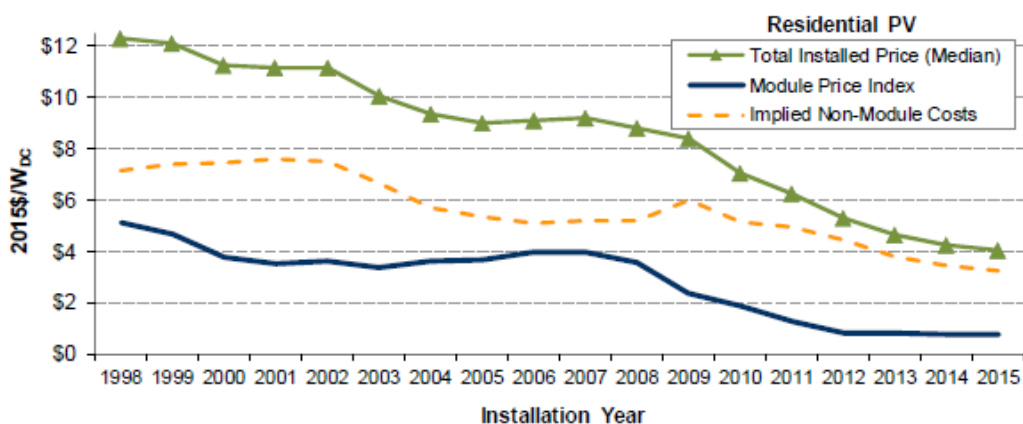


Another, extremely significant, spur to the growth of distributed energy resources has been the policy of net energy metering. Net energy metering refers to the practice of compensating customers with solar panels by simply allowing the customer's meter to "spin backwards" when more power is produced than consumed. This practice, once embraced by utilities as a simple solution for addressing the complex question of how to compensate customers who produce excess electricity at times, became problematic as the number of these customers grew. The problem with the practice is that customers are compensated at a per-kilowatt-hour rate that includes within it fixed costs for transmission, distribution, and customer service that the utility needs to recover. Technically, such fixed costs would best be recovered through a flat monthly customer charge, or a demand charge, but because of public and regulatory antipathy to the idea of setting a high fixed charge for customers regardless of the amount of electricity they actually consumed, most of these fixed costs have traditionally been "rolled into" the per-kilowatt-hour energy charge. Consequently, customers with solar panels are being paid for the energy that they are providing at a rate that is above what the actual avoided energy cost is for utilities, and are therefore being subsidized at the expense of other customers. (By paying distributed energy providers an amount that includes costs that the utility was actually supposed to collect from these providers, the utility is compelled to recover these costs by other means, which entails raising the price of electricity to all customers. Consequently, customers without solar facilities are paying extra to cover the benefit that solar energy providers received which exceeded its actual value to the utility.) In spite of the subsidy issue, most states continue to condone and even embrace net metering as a policy that promotes the development of distributed energy resources. Presently, forty-one states and the District of Columbia have net metering policies, although many are beginning to countenance the idea of allowing the utility to recover more of its fixed costs through higher monthly customer or demand charges, and/or allowing the utility to compensate distributed solar providers at the avoided cost of electricity only. The majority of states with net energy metering policies, however, still allow distributed solar providers to receive the full per-kilowatt-hour rate for energy provided, at least up to a certain

annual limit, and in these cases a very potent subsidy for the expansion of distributed resources continues to exist.

There are other government and regulatory policies, aside from net metering and those directly mandating increases in renewable energy, which are indirectly supporting the growth of distributed energy resources. At the national level, the Department of Energy, with its Quadrennial Energy Review, Grid Modernization Working Group, partnership with GridWise Alliance, and funding of research involving a number of grid modernization projects, is taking a leading role in promoting the vision of a decentralized, modernized electricity grid. Programs such as New York's Reforming the Energy Vision (REV), Minnesota's e21 initiative, Massachusetts' Grid Modernization Working Group, New Jersey's Grid Resiliency Task Force, and Hawaii's Power Supply Improvement Plan all support changes that are at least conducive to a greater reliance upon distributed energy resources. These will be discussed at greater length in the sequel to this report, which will focus on legislative and regulatory drivers of transactive energy, and the alternative regulatory models that could support them.

Declining costs have also contributed to the increasing popularity of distributed solar facilities. According to a recent report by Lawrence Berkeley National Laboratory⁴ (see graph below), the median installed price of both residential and non-residential solar photovoltaic facilities have fallen significantly during the seventeen-year period from 1998 to 2015. The median installed price for residential PV, which was about \$12/W_{DC} in 1998, had fallen to \$4/W_{DC} in 2015, which is an average annual rate of decline of about 6.6% per year. However, as the authors note in the report, the rate of price decline was steeper after 2009, and they attribute this initially to a drop in global PV module prices which was then sustained by declines in other hardware costs and "soft" costs. ("Soft" costs include such things as marketing, instillation, permitting, and other such expenses associated mainly with the delivery and installation channel.) If solar prices continue to fall at this rate, then in just a few years, the per-kilowatt-hour delivered price of distributed solar energy will attain parity – even without net metering subsidies and tax breaks – with more conventional, less expensive electric generation sources.



⁴ Barbose and Dargouth, "Tracking the Sun IX: The Installed Price of Residential and Non-Residential Photo-Voltaic Systems in the United States", August 2016, Lawrence Berkeley National Laboratory

4. Drivers of Transactive Energy

The growing presence of distributed energy resources is probably the single most important driver of transactive energy. As noted above, while their present level of saturation is low, this level is growing in both absolute quantity and relative share of total generation. And it is almost certainly no coincidence that in those states where renewable generation capacity penetration has exceeded 1% - the District of Columbia, Hawaii, California, Vermont, New Jersey, Massachusetts, Maryland, Arizona, Connecticut, Colorado, Delaware, Nevada, and New York – there has been a marked interest among legislators and/or regulators in exploring innovations in the workings of the electrical grid, including grid modernization, decentralization, and market models at the distribution level. There are, however, other factors that are also acting as catalysts for change, and these are described below.

The evolution to a transactive electricity system is often discussed under the more general heading of “grid modernization”, since it is assumed that a fundamental element of grid transformation will be the transition to a more decentralized electricity system, with more electricity coming from distributed energy resources, and many customers taking a more active role in managing their electricity service, as both consumers and producers of electricity. The GridWise Alliance has been tracking, by state, what it has determined to be the most important drivers of grid modernization, and reporting on these regularly, with the most recent update published in January 2016.⁵ The three general categories of drivers that have been identified, in declining order of importance, are 1) grid operations, which includes such things as the extent of AMR/AMI deployment, microgrids, and the presence of advanced communications and control technologies, 2) customer engagement, as reflected in dynamic pricing tariffs and other avenues for active customer interaction, and 3) state support, as evidenced by incentives or mandates that support grid modernization activities. According to the most recent report, grid modernization activities, based upon these three categories of drivers, are most prevalent (in descending order) in: California, Illinois, Texas, Maryland, Delaware, the District of Columbia, Oregon, Arizona, Pennsylvania, and Georgia. However, the report specifically highlights California, Massachusetts, and New York as “three states to watch”: California because of the many regulatory policies that have been passed to promote, among other things, the valuation and integration of distributed energy resources; Massachusetts, because of regulatory orders requiring utilities to submit 10-year grid modernization plans and introduce time-varying rates; and New York because of its “Reforming the Energy Vision” initiative which includes plans for the development of a distribution platform that will support greater integration of distributed energy resources.

States will play a critical role in shepherding the transactive energy process, and many have already begun to do so. Many are offering grants or prizes, for example, to fund microgrid projects, such as New York, California, and Connecticut. Others, such as Minnesota and Maryland, have sponsored studies to explore the future role of microgrids. And several have taken the lead in promoting and/or exploring the general concept of grid modernization, which generally entails a vision of a decentralized grid with many autonomous entities buying and selling electricity and other related services. According to the

⁵ “3rd Annual Grid Modernization Index”, January 2016, GridWise Alliance

GridWise Alliance report, cited above, the states which are presently at the forefront of supporting such activities are Illinois, California, Massachusetts, Oregon, Pennsylvania, Hawaii, New York, and Texas. It is interesting to observe that many of the states taking the lead in fostering grid modernization activities have gone through regulatory restructuring that involved the unbundling of electricity service into separate generation, transmission, and distribution entities, and the deregulation of generation to allow for competition. For these states, the move toward transactive electricity systems at the distribution level might merely be seen as the next phase in a process that began with restructuring and competition at the wholesale level more than a decade ago.

Any discussion of drivers must include an important observation: There is a pronounced lack of uniformity involving the extent to which each of these drivers are impacting change, and this lack of uniformity is evident in customers, utilities, and regulators. While it might be true, for example, that there is a new generation of “tech-savvy” consumers who expect and demand more choices and active involvement in any product or service that they acquire, including electricity, it is equally true that there is, and will continue to be, a base of customers who ascribe particular value to the fact that they don’t have to think much about their electricity service at all. As long as the level of reliability is acceptable, and the price is not unreasonable, this latter class of customers would consider it to be an imposition and decline in the quality of their service if they were suddenly required to invest more of their time in managing their electricity supply. This will be particularly true of residential customers, but may also apply to a significant share of commercial customers, and perhaps industrial customers as well. While smart appliances and other features of interactive automation might serve to reduce the need for customers to become “day traders in electricity”, there will continue to be a contingent for whom active supply management and even demand response will be considered to be a nuisance unworthy of any potential savings achieved. Any new transactive platform must accommodate the entire spectrum of customers on the system: from the active “prosumers” who both supply and receive electricity, to the traditional consumer who simply wants to be assured that the lights will come on when the switches are flipped, and that the bill for this service is not too high.

Among utilities, and state regulators, the willingness to embark upon new business and regulatory paradigms that support transactive energy will be driven by conditions within their respective jurisdictions. Such conditions include the existing and projected level of distributed energy resource penetration, the particular clean energy goals set by the state, the current price level of electricity, the level of electricity reliability and its vulnerability to extreme weather events, the economic health of the region, and even the political leanings of state legislators and/or regulators. The existing regulatory structure within a state will also be important, including whether it is a restructured state or one that still has vertically integrated utilities, if locational marginal pricing exists at the wholesale level, and if retail customer choice exists. Here, too, there will be a significant diversity among these conditions across the country, and this will result in different levels of commitment to and eventual adoption of transactive energy models.

While the evolution to a decentralized, transactive electricity grid is still very much in the embryonic phase – even in those states where the model is being aggressively explored – there has nevertheless been significant work done by a number of individuals and institutions in developing frameworks for how these new systems might actually work. The frameworks address such important issues as how

electricity supply and related services will be valued, how transactions will be managed on the grid, what particular technologies will be required for enabling the system, and what entities will be responsible for performing certain essential functions to support its operations. The next section will describe two such frameworks that show particular promise, and which are being considered by states that are currently at the forefront of the grid modernization movement.

Chapter 2: TE Market Structures

1. Introduction

Transactive Energy (TE) represents the methods to enable all wholesale and retail sellers and buyers of energy services to transact with each other. The focus of this chapter is on retail TE market structures on the distribution grid that are developing now and may evolve over the next 15 years or more.

This paper recognizes that there are emerging opportunities for distributed energy resource (DER) providers to offer a range of energy and grid services for wholesale and retail. This includes utility purchases of distribution grid services from DER providers as alternatives to traditional grid investments as is currently developing in California, Hawaii, Minnesota and New York. Additionally, peer-to-peer transactions are emerging as multi-user microgrids sell energy services to nearby customers across a utility distribution system as being considered in Boston⁶ and Pittsburgh⁷, for example.

TE will do more than just expand the focus of current transactions from the electric transmission system to the distribution system; it will enable transformation of grid operations. TE, at distribution and retail, will be shaped by market participants' and utilities' business models, regulatory structures, and their interactions.

This chapter provides a comparative discussion of two proposed approaches to implement TE markets at retail. TE at retail draws on several methods employed in wholesale electric markets and related controls used to achieve system reliability and economic efficiency. However, the retail distribution system is fundamentally different than the wholesale transmission system on several key dimensions. As such, this chapter will also highlight key considerations about how both new electricity markets⁸ may operate at the retail level and how they will need to interact with the continuing operation of wholesale power and transmission markets.

In several areas across the U.S. the current wholesale market is comprised of a) wholesale Transmission System Operator (TSO)⁹ operating spot markets for imbalances and b) forward bilateral energy markets to address the majority of participants' needs to reduce commercial uncertainty regarding price and availability. This chapter does not directly address TE for a vertically integrated utility, its customers and third-party distributed energy providers. The methods discussed could be adapted but would need further discussion.

⁶ Boston multi-user microgrid: <http://www.bostonredevelopmentauthority.org/getattachment/fa993b9a-d3ab-43a2-8981-94a7a49b8a33>

⁷ Pittsburgh developments: <http://www.districtenergy.org/blog/2015/07/21/pittsburgh-embarks-on-district-energy-plan/>

⁸ The term "markets" is used broadly to represent any type of transaction involving a buyer and a seller, this specifically includes utility tariff offerings and long-term bi-lateral contracts.

⁹ A TSO is also known in the United States as an ISO or RTO. We will use the term TSO here. The existing TSOs are CAISO, ERCOT, ISO-NE, MISO, NYISO, SPP, and PJM.

This chapter draws on the work of DOE's Gridwise Architecture Council, National Institute of Standards and Technology (NIST), New York REV's several working groups, and California's several working group efforts and the Smart Grid Interoperability Panel (SGIP).

Discussion of distribution level markets has been driven by public policy regarding improving overall system reliability and economic efficiency to create net benefits for customers. Retail and distribution markets are largely under the jurisdiction of state regulators as exemplified by the state laws and regulation in California, Hawaii and New York.¹⁰ Generally, these three states are seeking to capture the locational net benefits of distributed resources located on the distribution system and on customers' premises. These benefits include "reductions or increases in local generation capacity needs, avoided or increased investments in [transmission and] distribution infrastructure, safety benefits, reliability benefits, [environmental] and any other savings the distributed resources provides to the electric grid or costs to ratepayers of the electrical corporation."¹¹

The resulting market designs will need to consider a range of potential structural elements to realize the net benefits desired. This includes integrating existing and new various pricing schemes (rates, tariffs and market based prices), demand side management program design, and competitive market procurements for the deployment of cost-effective distributed resources that satisfy policy, market participant and utility objectives. Also, some distribution level markets may evolve to include an organized market for bi-lateral energy transactions across distribution as contemplated by some multi-user microgrids and by DER providers and retail energy service providers. Ultimately, this may also include a market structure for imbalance energy at distribution level.

Any discussion of TE market structures should also consider the level of market maturity and liquidity in an initial design and future evolution. Too often, market structure discussions ignore today's reality that the vast majority of distributed energy resources are located on customers' premises and compensated by existing net energy metering tariffs, other retail rate designs and/or demand side management programs. This means that most distributed energy resources cannot provide energy to another party. There are limited exceptions, but the amount is very small in relation to the liquidity needed to create a viable distribution level energy market. The primary focus of near-term TE market development is on establishing viable structures for pricing and sourcing distribution grid services as required in California, Hawaii and New York, and contemplated in the District of Columbia and elsewhere. Also, certain retail tariff structures, such as net energy metering will likely be replaced over the next decade by market oriented mechanisms including those highlighted in this paper. Plus, market structures that enable certain bi-lateral energy transactions such as multi-user microgrids will emerge. Further, there is a strong interest in establishing pricing and market structures that can integrate the full value of distributed resources across the power system, not just distribution.

Finally, the viability of any market design is equally dependent on meeting the needs of the buyers and sellers of services. This means, for example, supporting the business models of participants including

¹⁰ California Assembly Bill 327, §769, 2013; Hawaii House Bill 1943 "Grid Modernization", 2014; New York Department of Public Service, Reforming the Energy Vision, Case 14-M-0101

¹¹ California Assembly Bill 327, §769, 2013

considerations such as bankability of projects and management of other risks such as firmness of service delivery. As such, transactive energy markets are unlikely to be composed on a single structure. Instead, they will likely be comprised of several elements each addressing specific policy and participant objectives – much like the structure of the wholesale markets across the U.S. today. These objectives will shape the scope, scale and structures that are employed over time and will provide the lens by which to consider the discussion of conceptual market structures that follows.

2. A Foundation for Comparison of TE Market Structures

To provide a more complete context for Transactive energy and the development of market structures, it is useful to further define additional aspects to consider.

One aspect is consideration of the alignment to the policy objectives of a state or jurisdiction. Each state should clearly define the objectives for its particular needs. It is also useful to define the principal methods used in transactive energy – “markets” and “controls”. A general definition of a market is:

An actual or nominal place where forces of demand and supply operate, and where buyers and sellers interact (directly or through intermediaries) to trade goods, services, or contracts or instruments, for money or barter.

Markets¹² include mechanisms or means for (1) determining price of the traded item, (2) communicating the price information, (3) facilitating deals and transactions, and (4) effecting distribution. The market for a particular item is made up of existing and potential customers who need it and have the ability and willingness to pay for it.

Electricity markets as generically referred to in this chapter include wholesale/transmission grid and retail/distribution grid. These electricity markets may employ one or more of three general structures: prices (e.g., computed spot market prices, bid-based auctions, bid-ask based over-the-counter market clearing prices, tariffs with time-differentiated prices including dynamic prices); programs (e.g., energy efficiency and demand response) and/or procurements (i.e., request for proposals, bilateral contracts such as a power purchase agreement).

Physical control as in a grid control system is defined as:

The use of devices or mechanisms to direct, regulate, or stabilize the behavior of a physical device or system. Implicit in this definition is the idea that absent a device or system failure, the thing being controlled will always respond (within physical limits) to the control command or signal and that the control mechanism determines the behavior to be commanded.

In electric power systems, various market mechanisms and control systems are used over different time periods from multi-year resource and capital investment planning through real-time operations. Additionally, the integration of markets and controls becomes more tightly coupled over time,

¹² <http://www.businessdictionary.com/definition/market.html>

particularly in intra-day operations. For example, longer term planning for resource adequacy and transmission already include consideration of services that distribution connected resources may provide as an alternative to more traditional resources and investment. This is also increasingly a consideration in retail/distribution markets. To meet these long-term needs for resources, generally, long-term contracts are used. These forward contracts are generally sourced through competitive procurement processes or bilateral transactions reflecting market based solutions. This is also typically the case for energy transactions between non-utility parties. Long-term contracts and tariffs may be used for various ancillary and grid services at wholesale.

Real-time wholesale markets (day ahead and intra-day) have evolved over the past 20 years to better integrate and align market prices with physical control of the grid to address changes in previously scheduled service deliveries. These real-time markets are also called spot markets. This real-time optimization at wholesale markets with an ISO/RTO develops locational marginal prices (LMP) as a result of the optimal dispatch. LMP reflects the zonal or system level energy price plus the calculated basis differential which reflects the real-time transmission constraints, as well as losses, between a wholesale energy market delivery point and the transmission-distribution substation based LMP pricing point ("pnode"). An LMP value reflects an optimal re-dispatch of wholesale resources to mitigate constraints as well as reduce losses based on real-time state information of the physical grid power flows. Grid state information is an engineering based forecast of the system power flows. This state forecast is used to determining the economic optimization of various resources, based on pre-existing bids for a 5-15min intervals, to derive an LMP. This spot price may also be used to settle longer-term contracts that use variable pricing. In simple terms, the wholesale market is comprised of both long-term forward transactions and real-time spot markets largely used for changes to the previously contracted longer-term transactions and/or changes to the physical grid to ensure reliable and economically efficient operation.

The following section discusses two alternative distribution market structures that draw upon basic concepts from the existing wholesale market mechanisms above.

3. Two Alternative Retail Market Structures

The patchwork evolution of the retail market on a distribution grid, and the still developing wholesale markets for distributed generation, has resulted in a confusingly large number of variations in proposals for distribution level market-control structures. Two alternative approaches; TeMix and Distribution Marginal Pricing (DMP), illustrated in Figure 1, are introduced to facilitate a discussion on their potential applicability.

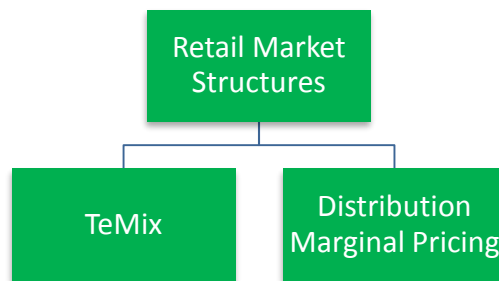


Figure 1: Retail/Distribution Transactive Energy Market Structures

These two alternatives represent the scope of the current discussions underway in the US and globally. It is hoped that this framing enables a cogent discussion of the considerations for policy makers and stakeholders.

TeMix: Two-Way Subscription Retail Tariff on an Automated Bilateral Transaction Platform¹³

Proposed by TeMix Inc., and hosted on a bilateral Transactive Energy Platform¹⁴, this approach features two-way forward subscriptions and spot transactions that coordinate retail generation, storage, and end use investments and operations. The transactions serve the load placed on wholesale markets in response to wholesale locational forward and spot tender prices as well as point-to-point forward and spot distribution prices. The Distribution operator (DO) continues as the regulated utility owner/operator of the distribution wires and poles facilities while offering distribution service under a two-way transactive distribution tariff. Important market participants are retail energy parties that include consumers, prosumers with distributed generation and storage and standalone distributed generation and storage. These retail energy parties buy and sell energy at the wholesale/retail interface in response to two-way transactive tariffs for energy at the retail/wholesale interface and distribution services to/from their facilities and that interface. These

¹³ This alternative is partially described in “A Model Interoperable Transactive Retail Tariff” at <http://www.sqip.org/Publication-Retail-Tariff>.

¹⁴ Retail Transaction Platforms for California, Edward Cazalet, “A Presentation to the Power Association of Northern California, April 21, 2015, [http://www.temix.net/images/PANC_April_21_2015_Presentation - Cazalet.pdf](http://www.temix.net/images/PANC_April_21_2015_Presentation_-_Cazalet.pdf)

transactions are hosted on transaction platforms that employ the OASIS/SGIP TeMix Profile standard protocols for Automated TE¹⁵. A roadmap for implementation of this approach has been published.¹⁶

Figure 2 illustrates the structure of a proposed TE structure that can be created with minimal organizational and regulatory change.

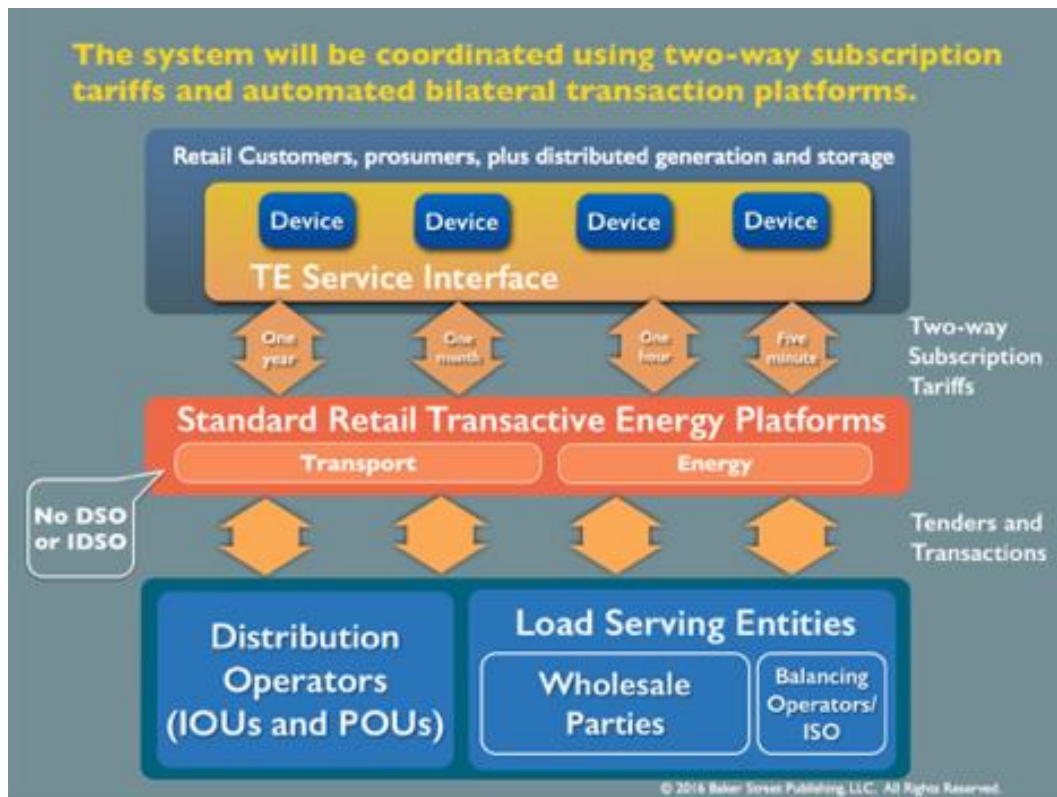


Figure 2: Structure for TeMix Two-Way Subscription Retail Tariff & Platform

In this market structure, a standards-based retail TE platform¹⁷ shown in the middle of the figure interfaces with the existing distribution operators (DOs) and Load Serving Entities (LSEs) at the bottom of the figure. These parties frequently post forward and spot tenders to buy and sell for point-to-point distribution transport and locational energy to each retail energy party as shown at the top of the figure.

The LSE interfaces with the existing balancing operator (e.g., a TSO) as well as forwards and futures electricity energy markets. The retail/wholesale energy market interface is at transmission

¹⁵ Cazalet, Edward G., "Automated Transactive Energy (TeMix)", Grid-Interop Forum 2011, <http://temix.com/images/GI11-Paper-Cazalet.pdf>.

¹⁶ "A Roadmap toward a Sustainable Business and Regulatory Model: Transactive Energy". Stephen M. Barrager, Ph.D., and Edward G. Cazalet, Ph.D., April 2016, http://www.temix.net/images/51_State_II_20160308_Submission_Narrative_copy_2.pdf.

¹⁷ http://www.temix.net/images/PANC_April_21_2015_Presentation_-_Cazalet.pdf

substation for the feeders that provide two-way delivery between end customers and the transmission substation. Forward and spot tenders for energy are frequently posted at the retail/wholesale market interface by the LSE.

This two-way subscription tariff provides a simple transactive interface for end customers and distributed resources. The energy subscription is based on forward tenders from the existing wholesale markets. The transport tariff is two-way and it recovers more of the fixed cost of distribution when the distribution feeder and substation is more fully loaded in either direction. This results in a dynamic price for each feeder and perhaps at different locations on the feeder.

As illustrated in Figure 3, a subscription provides customers with a fixed amount of net energy (use less generation) in each hour of a year or several years at a fixed monthly payment. The payments cover all fixed and variable costs. Typically, a separate tariff is provided for energy and transport. Customers are paid a spot price for any unused subscribed energy and pay the same price for any excess energy used in relation to the subscribed amount in each hour.

The subscription is simply a set of forward transactions between a customer and one or more retailers. Similarly, the spot payments are spot transactions for the imbalance between the forward transacted amount and the metered delivery. The two-way subscription tariff is also called a transactive retail tariff.¹⁸ In summary, here is how it works:

¹⁸ <http://www.sqip.org/Publication-Retail-Tariff>

Example of how a two-way subscription TE tariff works for a typical retail consumer.

- Based on my typical usage or production, I automatically transact for subscriptions for prescribed quantities of energy and transport in each hour of the year(s) for a fixed monthly payment (subscription.)
- If I use less than I subscribed for in each hour then I am paid for the difference at spot prices.
- If I use more than I subscribed for then I pay for the difference at spot prices.
- As my needs change I can automatically buy or sell to modify my subscriptions at the current tendered prices from a Transactive Energy Platform.

This means stable bills for customers and stable revenues for distribution operators and energy suppliers.

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Figure 3: Two-Way Subscription Retail Tariffs

Energy is transacted at the retail/wholesale interface. The transport price (both spot and forward) is calculated using a formula that recovers more of the largely fixed distribution costs using a higher price of transport when the transport is more heavily loaded in either direction and less of the costs using a very low price when the transport is lightly loaded in either direction. Alternatively, an LSE can provide bundled energy and transport delivered to the customer facility.

The two-way subscription retail tariff is especially useful with a conventional distribution operator that does not dispatch generation or demand response. With the two-way tariff, distribution transport is more expensive when the line is heavily loaded in either direction. From time-to-time, under regulatory scrutiny, the steepness of the distribution price formula is adjusted to reflect long-run investment costs of distribution and short-run congestion occurrences. Additionally, the distribution owner based on long-term planning can offer incremental long-term subscriptions for additional two-way distribution capacity at prices that recover investment costs and could be higher than the costs of the subscriptions already contracted for. This approach can be implemented with very little changes to existing business and regulatory models and little hardware investment assuming interval meters are already in place.

Together the transport and energy tariffs may initially encourage end user generation investment such as PV, but as PV investments reach the level that causes reverse flows mid-day and large flows

to serve evening uses, the transport tariff and energy tariffs will encourage end user and third party investment in storage or storage + solar. Or, depending on the prices and availability of tendered subscriptions for additional distribution capacity as described in the previous paragraph end users and third party owners of distributed generation and storage may decide to subscribe to additional distribution capacity.

End-use customers can also post tenders for energy at the retail/wholesale market interface. Such customers can post peer-to-peer transactions with neighbors. The payments for distribution transport for a transaction between two close neighbors will largely net out, so there will be little cost disadvantage to transactions at the substation and transactions in the neighborhood between two close neighbors.

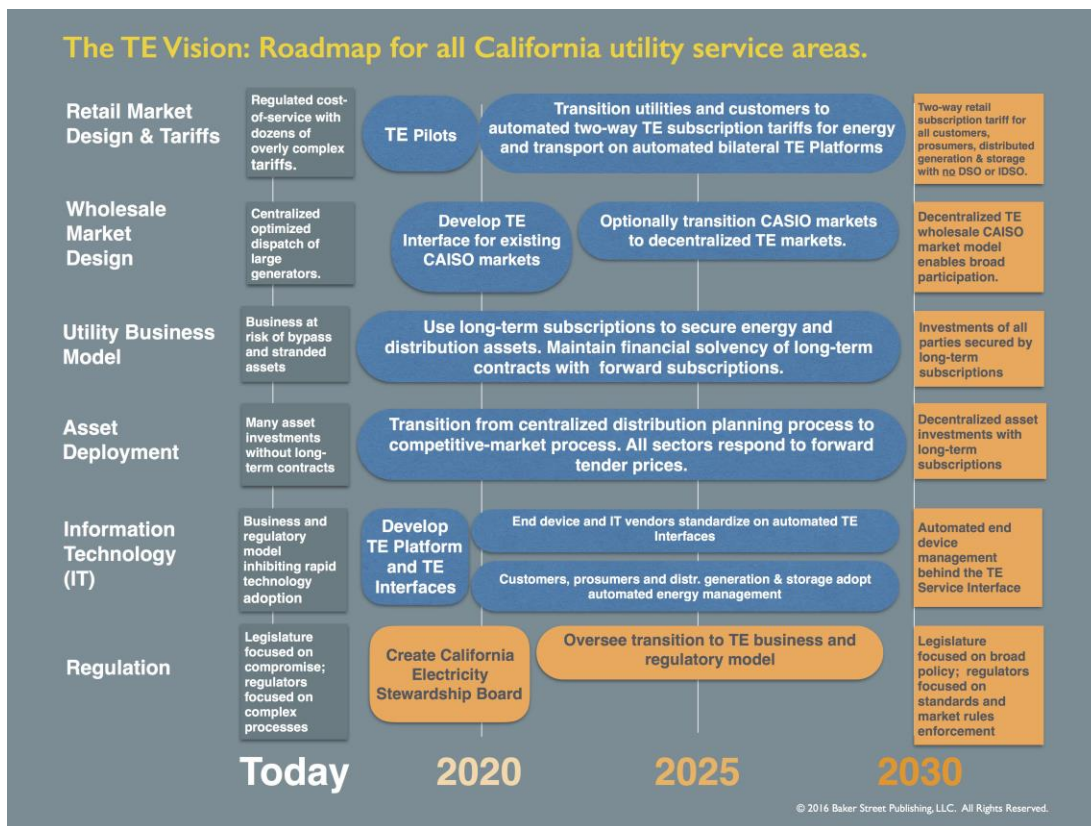
Customers without automation can modify their energy use manually and likely save money. Automated customer devices can respond to the spot and forward tender prices and save money for the customer. Or, customer devices can use the forward prices to optimize their operation and communicate to the service interface their proposed forward production and consumption of energy. The energy management system associated with the service interface accepts tenders to create transactions for energy or create tenders.

The use of a simple formula for distribution prices reduces and defers the need for complex, expensive sensor and optimization software for distribution feeders. It also means that smaller distribution utilities can afford to employ TE on feeders with limited capacity and/or two-way flows. Optimization can still be applied to distribution operations.

The LSE parties can be franchise monopolies or multiple competitive retailers. Customers receiving multiple tenders from competitive retailers would typically select the lowest price offer to sell to them or the highest price offer to buy from them. Spot prices for energy would typically be set. As discussed earlier, such markets would be subject primarily to state regulation with FERC potentially involved in any transactions at the wholesale level.

The transformation of a power market to a TE model based on the TeMix approach is illustrated by the California Market Transformation Roadmap in the figure below using the six “swim lanes” set forth by SEPA in the 51st State Phase II¹⁹.

¹⁹ “A Roadmap toward a Sustainable Business and Regulatory Model: Transactive Energy”. Stephen M. Barrager, Ph.D., and Edward G. Cazalet, Ph.D., April 2016, http://www.temix.net/images/51_State_II_20160308_Submission_Narrative_copy_2.pdf.



The transformation begins with TE pilots to deploy the two-way subscription tariff on TE Platforms. One such pilot is now underway²⁰. Following the pilots, the standard Transactive Energy Platforms can be deployed and configured from secure cloud servers over about five years for many IOU and POU LSEs, DOs and other non-utility LSEs.

The two-way subscription tariffs will be phased in by customer choice and by customer sector, DO and LSE. Low income customers can be offered discounted subscriptions but should be able to respond automatically to spot tenders to save more money. Existing net metering, TOU, demand charge and demand response programs will be phased out in order to be replaced by the simpler subscription tariff model for all customers and other retail energy parties.

No changes to the wholesale markets are necessary. The next logical step for an ISO is to implement standard wholesale TE Platforms for energy at distribution/transmission substations. Forward planning will increasingly be done by customers, commercial distributed generation and storage owners, the distribution and transmission owners and less by the legislature and regulators.

²⁰ “Retail Automated Transactive Energy System (RATES) Funded by California Energy Commission (CEC) EPIC Grant GFO-15-311”, http://www.temix.net/images/GFO-15-311_Retail_Automated_Transactive_Energy_System.pdf.

By year fifteen of an evolution, like California's, IOUs and POUs will continue to own the regulated distribution operators (DOs). With TE there is no need to create distribution system operators (DSOs)²¹ that act like ISOs for the distribution grid. This greatly simplifies the DO business model.

The transitions to utility business models with separate and competitive LSEs and regulated DOs can be gradual. It also will be facilitated by the transition to subscription tariffs. Subscription tariffs for DOs are long-term contracts with customers that can support stable revenues for the DO investments and business model. This will help to minimize stranded assets, but as with any industry technology changes can strand assets and business model, so the sooner a utility transitions to long-term, more commercial contracts acceptable to both the customer and the LSE or DO the better for all.

When the distribution feeders and substations reach the point that capacity increases in either or both directions are needed then the customers on those feeders should agree to pay for the increases by purchasing additional distribution transport subscriptions.

Once the TE model is in place, regulatory and policy-making bodies will be able to focus on promoting competition and avoiding economic abuses. The TE forward transactions will greatly reduce the incentives for market manipulation of spot markets and will contribute to reliability. The existing wholesale markets provide a liquid competitive energy market at the transmission/distribution interface and cost of service two-way distribution transport assures fair markets for energy delivered and sources from customers and distributed assets.

Distribution Marginal Pricing

A second approach, Distribution Marginal Pricing (DMP) is based on introducing prices for the incremental value that DER may provide to operate the distribution reliably and more efficiently. This value is based on the applicable long-term and short-term marginal costs of distribution capacity investments and certain operational expenses.

Today, retail rates combine prices for energy, transmission, and distribution service as well as other utility cost recovery and/or policy based charges. This discussion will focus on the distribution component as the energy and transmission components, from a transactive perspective, are currently recognized as wholesale products and subject to the corresponding wholesale market structure and regulatory construct. The FERC-state regulatory jurisdictional roles are not expected to change in the U.S. through 2030.

Distribution prices in the U.S. are usually comprised of three parts; a volumetric price, a demand based price, and a fixed service fee. These prices are derived administratively from a utility's revenue requirement and a cost of service analysis that is linked to distribution planning and operational factors. Distribution rates are undergoing a change across the country reflecting the changing use of the grid by customers and developers with DER integration. Additionally, as several

²¹ P. De Martini and L. Kristov, *Distribution Systems in a High DER Future*, Lawrence Berkeley National Laboratory, 2015

states are pursuing resource policies with significant DER contributions, efforts are underway to align distribution pricing to its use and costs. There is a movement toward a simpler 2-part distribution access fee that is comprised of a demand charge based on maximum demand (irrespective of power flow direction), and a fixed charge component.

This foundational distribution access charge is expected to be a standard retail tariff as part of an open access type construct. A version of this approach already exists in states with retail access whereby the energy services provider pays the distribution charge for delivering the competitive energy supply to the customer. Or, in the case of a DER resource that is participating in the wholesale market, the access fee is to transport services to a transmission delivery point.

In the DMP model, disaggregated distribution access prices are augmented with overlay prices that are based on the long-run and/or short-run marginal costs of the distribution grid. These marginal costs are determined through distribution planning (long-run marginal cost) and real-time operational needs (short-run marginal costs). An example in more traditional tariffs is the overlay price used in Critical Peak Price (CPP) or Peak Time Rebate (PTR) offerings, which provide an additional incentive on top of the underlying retail rate. In the DMP case, for example, this would be an added price paid for a specific response from DER(s) to defer substation capital investment.²²

Long-run DMP

California²³ and New York²⁴ are currently developing distribution operational markets to enable DERs to provide services as an alternative to utility capital investments and operational expense. This market is not dissimilar to that for wholesale capacity -- transmission non-wires alternatives and ancillary services. At distribution, the potential types of services may include distribution capacity deferral, steady-state voltage management, transient power quality, reliability and resiliency, and distribution line loss reduction. The distribution utility is the buyer of these services, in lieu of traditional expenditures, to meet its statutory obligations for a safe, reliable distribution grid. The distribution planning process defines the need for these grid operational services.²⁵ More importantly, DER services that are not needed should not be sourced.

²² Insert reference to ConEd BQDM targeted DR incentive

²³ California Public Utility Commission, Docket R.14-08-013, Distribution Resources Plan

²⁴ ConEdison, Brooklyn Queens Demand Management program, <https://www.coned.com/energyefficiency/pdf/BQDM-program-update-briefing-08-27-2015-final.pdf>

²⁵ M. Esguerra, "Distribution Services, Attributes and Performance and Measurement Requirements" presentation pp.34-39, July 2016 http://drpwg.org/wp-content/uploads/2016/07/LNBA-Working-Group-072616_FINALVERSION.pptx

Accordingly, if grid needs are identified, services provided by DER providers and customers may be sourced through a combination of three categories of mechanisms:

- a. **Prices** – DER response through time-varying rates, tariffs and market-based prices
- b. **Programs** – DERs developed through programs operated by the utility or third parties with funding by utility customers through retail rates or by the state
- c. **Procurements** – DER services sourced through competitive procurements

Determining an optimal mix from these three categories, plus any grid infrastructure investments, requires both a portfolio development approach and a means to establish a comparative basis for these alternatives in terms such as firmness, response time and duration, load profile impacts, and value (net of the costs to integrate DERs into grid operations). Any mix of DER sourcing methods requires that specific operational needs and criteria be met in order for economic value to be ascribed. It should be noted that there is little experience with sourcing DER for distribution services to date, although several large demonstrations are underway in California, Hawaii and New York.

Pricing of distribution services may be based on the long-term locational avoided cost of traditional investments to inform a price or rebate, or via competitive procurements that use avoided cost to establish a ceiling price. Alternatively, locational avoided cost method for long-run marginal price may use a more sophisticated optimization model. The optimization model, as described by Integral Analytics, calculates long-run DMPs via a centralized iterative optimization of the distribution power flows and the economic dispatch of DER for a particular distribution system. A challenge with this approach is assembling the operational and economic data necessary to achieve the optimization. This approach updates this information in a cost calculation based on batch processing of granular grid data from a utility's distribution power flow tools to determine the Optimal Power Flow (OPF), which is converted into avoided cost estimates and then input into an economic optimization engine to determine the DMP.

Convergent Locational Marginal Pricing

Several states are looking beyond distribution marginal pricing to include the locational and system-wide wholesale along with the societal value of DER. For example, the New York Public Service Commission (NY PSC) introduced the concept of adding a distribution price ("D") to the existing NYISO locational marginal price (LMP) for wholesale energy to create a single unified pricing signal for specific times and locations on the distribution system. This D price is intended to expose the value of distribution grid to include capacity constraints, losses, reliability, voltage, and power quality. The NY PSC ordered the utilities to develop LMP+D methods for implementation.²⁶

²⁶ Case 15-E-0082, Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program, Order Establishing a Community Distributed Generation Program and Making Other Findings (issued July 17, 2015).

A key challenge is to properly align the respective price components in the right *value-stacks* in order to properly reflect the benefits and costs across a power system. This requires proper distribution investment value components combined with the appropriate transmission and generation price components, to the extent the latter should be included, while also accurately reflect cost-causation (net deferral or avoidance). Interactive effects between key factors such as weather, loads, and prices should also be addressed.²⁷

Integral Analytics²⁸ has proposed an optimization method to integrate energy, transmission and distribution pricing. In their terms, *“the DMP methodology produces marginal distribution cost values that are linked to specific DERs at specific locations and include **both** forward fixed and variable costs, incorporating both the grid and traditional supply drivers.”*²⁹ The long-run approach is intended to co-optimize both distribution grid and supply (generation and transmission) costs across both short-term operational and long-term planning dimensions. This is accomplished through a bottoms up “Distribution IRP,” which *“in planning, DMP least cost optimizations can be couched as “mini-IRP” models, circuit by circuit, which complement the analysis already performed by LMP as well as traditional IRP analysis, and which incorporate the richness and detail of what already exists in an LMP.”*³⁰

The analysis incorporates both supply-side avoided costs and distribution-side avoided costs, including KVAR, power factor, voltage and other influences not found in supply-side IRPs where only KW and KWH are the focus. The Distribution IRP is similar to traditional IRP, with DER costs, grid and operational costs being jointly co-optimized. This is not unlike how the optimal mix of a supply resource stack and DSM programs is determined, but with a twist. Optimal customer behavior can also be captured in the optimization. The mathematical optimization methods are more advanced than those used for traditional IRPs. The result of this optimization is a “system lambda” or DMC value that can include the traditional \$/kW and \$/kWh, as well as \$/KVAh to integrate reactive power dimensions. The DMP is the “shadow price” from the marginal cost calculation and can be used as a price in markets. IA describes four types of DMPs as illustrated in the figure below.

²⁷ Proper correlation of these factors can capture much of the interactive effects, typically through covariance analysis.

²⁸ T. Osterhus and M. Ozog, *Distributed Marginal Prices (DMPs) and Cost Optimization*, Integral Analytics, 2014

²⁹ T. Osterhus, M. Ozog, and R. Stevie, *Distribution Marginal Price Methodology Applied to the Value of Solar*, April 2016, pg. 1.

³⁰ Ibid, pg. 4.



Figure 2: Four Main Components in Distribution Marginal Costs

The long-run DMPs provide for integration and optimization of DERs across three dimensions: customers, the distribution grid, and the bulk power system. Key aspects of this approach is the marginal or incremental costs bids, assumptions, and conversion factors can be dimensioned in a single denominated value, such as \$/kWh or \$/kVAh. Probabilistic elements are included based on covariance, to reflect uncertainty in weather, loads, prices, and performance, which increase the accuracy of DMPs.

Short-run DMP

The NY PSC is also exploring the potential to develop a value of D in the “LMP+D” construct that is based on short-run distribution marginal value.³¹ While the specifics are not yet fully defined, the PSC is pursuing development concurrent distribution spot markets that closely align with NYISO LMP pricing on a 5-15 min basis.

The D value would, in effect, reflect the calculated basis differential (reflecting real-time distribution constraints and losses)³² between the LMP node at the transmission-distribution substation and a specific point on the distribution feeder. LMP+D would reflect the value of energy at a single distribution node for distributed resources providers, Load Serving Entities (LSE) and end customers through an organized market. The LMP+D spot prices would be used as the primary index price for distribution level energy transactions. It is not yet clear how this short-run D price would apply for

³¹ Case 15-E-0082, Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program, Order Establishing a Community Distributed Generation Program and Making Other Findings (issued July 17, 2015).

³² LMP+D and DMP require accurate distribution asset mapping, real-time distribution state information and distribution state estimation models to perform the pricing calculations. These prerequisites do not yet exist and are not likely until the next decade.

grid services sourced by utilities. Or, whether this real-time D price will provide the market needs of DER providers for revenue certainty to support financing capital projects or correspondingly that of utilities' needs for firm commitments to address capital deferral opportunities.

One approach to short-run location marginal pricing is proposed by Integral Analytics. IA proposes to adapt techniques from short-run bid-based distribution and LMP markets to derive integrated short-run DMPs at specific points on the distribution system. *"DER operational dispatch costs or prices are essentially short-run DMPs (hourly or 5 minute) that can be bid-based in the same way that LMP prices are issued. These cost signals reflect the [short-run] incremental resource cost for a specific DER at the specific node or location."*

Another approach is described in a 2016 paper by Caramanis³³. A distributed computational method is proposed to develop LMP+D pricing that involves marginal-cost-based dynamic pricing of electricity services, including real power, reactive power and reserves. This approach extends techniques at wholesale through a distributed methodology that enables "transmission and distribution locational marginal price (T&DLMP) discovery along with optimal scheduling of centralized generation, decentralized conventional and flexible loads, and distributed energy resources (DERs)."³⁴ This approach includes adaptations of wholesale models and new algorithms to address the uniquely different topology and operation of the distribution grid. The authors claim to be able to determine "T&DLMPs while capturing the full complexity of each participating DER's intertemporal preferences and physical system dynamics."³⁵

However, the authors recognize the massive challenge of optimizing across multiple space and time scales, including:

- Wholesale: annual long-term system-wide and regional, monthly nodal, day-ahead operational planning, hour-ahead adjustment to uncertainty, 5-min economic dispatch, response to 2-4 seconds regulation signals, and real-time frequency control.
- Distribution: annual long-term distribution planning area, annual operational planning, intra-month circuit switching for maintenance and load balancing and real-time switching for outage restoration and power quality.

A significant assumption in the IA and Caramanis methods above, as noted by the authors, is the existence of an extensive distribution grid sensor network, a low latency and high bandwidth communications network, and a cost-effective distributed computing platform at each distribution substation to perform state estimation along with the distribution marginal cost optimization calculations in coordination with the NYISO LMP calculations. Developing this capability may extend well beyond 2025. Efforts have been initiated to achieve some of these aims with cloud-computing.

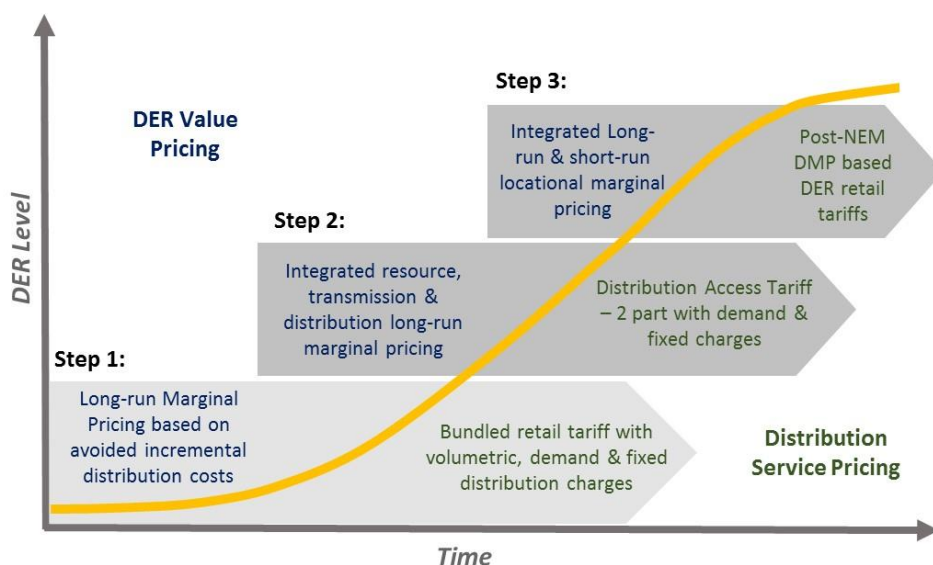
³³ M. Caramanis, et al., *Co-Optimization of Power and Reserves in Dynamic T&D Power Markets With Nondispatchable Renewable Generation and Distributed Energy Resources*, Proceedings of the IEEE, 2016.

³⁴ Ibid.

³⁵ Ibid.

DMP Roadmap

The evolution of distribution marginal pricing will be linked with changes to the underlying distribution rate design as we move toward an open access tariff in a post-net energy metering environment that more fully allows market forces to price the value of DER. DMP, as a result, will more fully emerge as the means to price the marginal value of both long-run capital investments as well as short-run operational services. The current method of determining the marginal price based on the avoided incremental long-run distribution costs will be the first step. The second step will be the alignment of long-run marginal distribution costs with the long-run resource adequacy and transmission costs to develop a converged marginal price. The final step will be the development of a short-run locational marginal price on distribution that aligns with wholesale energy locational marginal pricing. The figure below illustrates this evolution.



4. Comparisons of the Two Alternative Retail Market Structures

The purpose of this section is to provide summary comparisons of the two structures without making judgments or advocacy for one over another. Our goal is to help readers understand the range of structures under discussion and to provide information as a basis for more informed decisions and further development of the alternatives. The evolution of transactive energy markets at distribution will likely adapt aspects of wholesale methods and practices, drawing on elements of the models described in this chapter. These models will need to be adapted for the unique characteristics of distribution. The relative sophistication of various methods will need to be aligned with requisite distributed market liquidity and opportunities to create net benefits for all customers.

Table 1 lists a set of attributes for each of the two structures.

Table 1: TE Market Alternatives Comparison

Attributes	<i>TeMix: Two-way Subscription Tariff</i>	<i>Distribution Marginal Price (DMP)</i>
<i>Capture Forward Deferral & Other Benefits in Planning</i>	Investment and investment timing of all parties using forward planning by parties is coordinated using forward transactions and subscriptions	Incremental cost bogy used with competitive procurement to define infra-marginal cost for bilateral contracts
<i>Distribution Operation</i>	Distribution Operator (DO)	Distribution Operator (DO) initially Distribution System Operator (DSO) later
<i>Coupling Between Short-term Market & Dispatch</i>	Self-dispatch by retail end customers and distributed generation and storage	Bid-In DO and ISO dispatch a customer response to augmented retail tariffs
<i>Retail Energy Market Operation</i>	Two-way Subscription Tariffs and forward bilateral transactions coordinated with ISO LMP markets for balancing.	Forward Bi-lateral market + ISO LMP settlement on residuals
<i>Distribution Transport Service</i>	Two-Way Subscription Tariffs and spot pricing by DO	Distribution Access Charge (2-part tariff) by DO
<i>Retail Energy Market</i>	Competitive or franchise retail and municipal models	Retail access model (as currently exists is several states)
<i>Secondary Retail Products</i>	Energy transactions on short duration intervals for frequency regulation and reserves, capacity-like energy options, and Reactive Power	Reliability, Voltage/ VAR & Power Quality
<i>Distribution Grid & Other Retail Services</i>	Reliability, Resilience, & Power Quality	Reliability, Resilience, & Power Quality

We note that initially the two approaches rely on the use of a Distribution Operator (DO), though with abilities to schedule and achieve more nuanced DER operations (some may adopt Distributed Energy Resource Management Systems of DERMS). Later the DMP alternative is expected to use a new Distribution System Operator (DSO). A DO is utility owned and it manages the distribution grid without dispatch control over end loads or distributed generation and storage except in an emergency. A DSO is a DO that also dispatches bid-in end loads and distributed generation and storage. Both DO and the DSO

are responsible for the reliability of the physical distribution grid and enforcement of grid constraints on energy transactions.

Both transactive energy models would not focus merely on short run energy transactions but capture forward capital cost deferral and other benefits. The coupling between market prices and dispatch would also differ considerably between the two alternatives. TeMix employs a near continuous forward process wherein distributed end load, generation and storage are self-dispatched based on spot energy tender prices tied to the wholesale (LMP) market with retail energy adders for energy related costs not in the LMP and circuit specific spot transport tender prices from the DO. The resulting schedule changes are frequently communicated to the ISO/RTO and DO. In contrast, in the longer-run DMP DERs are bid into DSOs and prices result in DER dispatch. Additionally in the DMP alternative time-differentiated retail tariffs augment dispatched DER prices.

In the TeMix alternative, retail energy market operations are achieved by LSE energy (tied to ISO LMPs) and DO transport forward and spot tenders in the TeMix alternative. In the DMP case energy dispatch continue to be administered as part of ISO market operations. In the TeMix alternative energy is not cleared by the DO because that would require a level of liquidity in distributed generation and storage that does not exist and a willingness of end users to bid-in complex offer curves and wait for DSO or ISO dispatch.

At the distribution transport level, TeMix would rely on the Two-way Subscription Tariff and spot tenders from the DO. The DMP alternative would use DSO incremental bid prices by participants, not unlike an ISO/RTO. Scheduled transactions in modern ISOs/RTOs must submit incremental bids for congestion pricing, which seem analogous for DSO operations to schedule DER services.

Both approaches use forward planning of distribution investments. In this regard, both alternatives rely on planning processes (that address investment deferral) by the DO/LSE and market participants. In the TeMix this includes coordinated forward transactions including the Two-way Retail Subscriptions. DMP uses a planning process to determine the forward capital cost deferral value. If competitive bidding is used to defer distribution capital projects, the DMP at the planning level would be the ceiling price, cloaked in confidentiality to avoid gaming and future speculation. The respective winning bid prices would determine the basis for DMP pricing for the bilateral contracts.

Other retail products, such as frequency regulation, reserves and volt/VAR service, much like ancillary services in ISO/RTO markets, are characterized in the TeMix alternative as forward options on energy, reactive energy as a separate energy product, and short-duration energy transactions for frequency regulation. In the DMP alternative the DSO will offer these other retail products as separately defined products based on a competitive procurement, possibly with confidential reference to related avoided cost and the real optionality of services such as voltage management.

Power quality is the responsibility of the DO in the TeMix alternative and the DO/DSO in the DMP alternative. Reliability of the distribution wires delivery service is also the responsibility of the DO in the TeMix alternative and the DO/DSO in the DMP alternative. As end customers become prosumers or participate in microgrids more of the traditional resource adequacy responsibly of LSEs will be taken on

by the end customers. In both alternatives resiliency to survive in disasters and portfolio diversification seem likely to be the joint responsibility of the market participants, LSE, DO or DSO, legislators and regulators.

Chapter 3: Business Models for Transactive Energy

This chapter describes the new electric power industry business models that could emerge or evolve to create value from a transformation to Transactive Energy (TE). As noted in the first chapter, one widely-used definition of TE is:

A system of economic and control mechanisms that allows the dynamic balance of supply and demand across the entire electrical infrastructure using value as a key operational parameter.

From the perspective of defining business models, the key word in this definition is “value.” The objective of TE is to bring DER into the electric system based on its value to consumers and the electric system as determined by market prices. TE is seen as a way to empower consumers, lower costs, increase resiliency and realize environmental benefits. Such electricity markets would have different business models than today’s electricity industry. Businesses would need to create value for prosumers and consumers alike and to capture enough of that total value for themselves to be financially viable.

New types of businesses will be needed to serve prosumers and the roles of some existing organizations may change. For a TE market to succeed, these business and organizations must have viable business models. A *business model* is the overall plan of an organization to achieve its goals. It is how the organization generates revenues and creates a *margin* (excess of revenues over costs) from operations (a profit, if it is a for-profit entity), including the reason why customers would see value in buying its services (the *value proposition*). All organizations, even non-profits and governments, must have sustainable business models. Otherwise, they could not be viable economic entities. As markets are created that enable the participation of DER over the distribution system, a diverse set of business models will evolve reflecting specific market and regulatory conditions and business strategies in each market. Business models serving retail customers in different ways are likely to co-exist and evolve in different—and perhaps unexpected—ways.

1. Current Electricity Business Models

The preponderance of electricity produced in the United States is now sold and/or distributed to end-use consumers by three types of electric utilities: state-regulated, investor-owned electric utilities; electric distribution cooperative utilities; and public power utilities. In addition, market forces are already being felt in states with retail competition for at least some electricity consumers, and competitive business models have already emerged in those states.

Traditional business models for regulated utilities include:

- Regulated, vertically-integrated, investor-owned electric utilities are subject to cost-of-service regulation by states for their retail functions and by FERC for wholesale market activities. These have historically been the most common type of entity serving end-use customers. Today, some vertically-integrated utilities are in regions where there is no Independent System Operator (ISO) or Regional Transmission Operator (RTO) but others are in regions where ISOs or RTOs operate the wholesale electric market. The actual business models of vertically integrated utilities are quite varied. Some are owned by holding companies that also own unregulated affiliates that perform other functions in the electric power or energy industries. Still, in terms of meeting the needs of their retail customers in regulated markets, they have much the same value proposition.

Value proposition: Economies of scope and scale reduce costs while cost-of-service utility regulation by both states and the federal government ensures cost control and fairness.

- Electric distribution cooperative utilities are one of two basic types of rural electric cooperatives (the other being Generation and Transmission (G&T) cooperatives that sell wholesale power to the electric distribution cooperatives that are their members). Distribution cooperatives perform the power distribution function and serve end-use customers that are their members, mostly in rural areas, but also increasingly serve expanding suburban areas. Most distribution cooperatives are very small. There are over 800 distribution cooperatives in the United States.

Value proposition: Electric cooperatives are not-for-profit energy service providers that work for the benefit of their members and, as such, have an incentive to adopt technologies such as DER that benefit their members. Members gain access to electricity at a lower cost than would otherwise be available by working together and accessing capital at a lower-than-commercial rate from the federal government. Distribution cooperatives are locally-controlled by consumers.

- Public power distribution utilities include municipal utilities and public power districts. These utilities are owned by the government jurisdiction whose citizens and businesses they serve. These are not the only types of public power utilities. For example, some public power utilities are fully integrated from generation through distribution, but many are distribution only. Others only perform the generation function or only have generation and transmission functions. Distribution public power utilities are discussed in this chapter because, like distribution cooperatives, they serve end-use consumers and would be most directly affected by changes in the retail electricity market design.

Value proposition: Public power utilities are operated by local governments to provide their citizens and communities with reliable, responsive, not-for-profit electric service. These utilities are directly accountable to the people they serve through local elected or appointed officials.

The business models that have emerged in competitive retail markets are, to an extent, harbingers of what could emerge under TE market frameworks. They vary by state due largely to differences in the laws and regulations governing retail competition. Competition on price has evolved to differentiated services targeted at addressing specific consumer preferences such as risk management, renewable

purchases and special billing and payment options. Although they likely would change in a future TE marketplace, several business models have emerged in these markets:

- Utility transmission and distribution (T&D) and retail sales business models are mostly modifications of vertically-integrated investor-owned business models in states with competitive retail markets. These utilities are organized to comply with limitations on utility marketing efforts and, in some jurisdictions, requirements for generation asset divestiture. Where consumers have not chosen to purchase their electricity from retail power marketers (see below), these companies may serve those consumers as a Provider of Last Resort (POLR) at a regulated electric rate.

Value proposition: T&D remains a regulated monopoly service subject to federal and state commission regulation. Perceived competitive pricing with other suppliers is offered along with ease of staying with the incumbent utility.

- Retail power marketers compete to provide electric services to consumers. The emergence of retail power marketers has not only provided for competition based on price, it has also created innovations in the services offered to electric customers.

Value proposition: The power marketer provides lower cost electricity and, if requested, energy from renewable resources.

Five business models are not limited to competitive retail electric markets and already provide ways for consumers to compete in electricity markets:

- Combined Heat and Power (CHP) is the simultaneous production and use of electricity and thermal energy in a single integrated facility, usually at a consumer's site. Utilities have been required to purchase power from qualified CHP facilities since 1978.

Value proposition: For facilities with an appropriate balance of electric and thermal loads and substantial energy costs, CHP offers less expensive thermal and electric energy with lower price risk and greater self-reliance for reliability. For some industrial facilities, the CHP facility makes use of a combustible waste product as a fuel.

- Demand response aggregator combines the performance of end-use customers to provide larger and higher-value demand response services to electric markets. Demand response aggregation is already being provided in competitive wholesale markets.

Value proposition: Consumers can make money by reducing load or self-generating in response to requests. The aggregator can do this more easily and/or profitably than the customer acting alone.

- Community choice aggregation (CCA) is a local government purchasing electricity on behalf of its residents and businesses in order to reduce costs and often to ensure the acquisition of renewable energy.

Value proposition: *Power purchased through the CCA can be lower cost due to greater market power and ability to negotiate, power that is more locally produced and controlled, and/or green power.*

- Community solar consists of a solar-electric system that, through a voluntary program, provides power and/or financial benefit to, or is owned by, multiple community members. Several community solar business models have been implemented, including utility-sponsored projects, special-purpose entities, and non-profit models.

Value proposition: *Community solar enables multiple energy consumers to share in the benefits of a local solar facility that can take advantage of economies of scale and enable investors, some of whom may be customers for the output, to realize tax benefits.*

- Energy Service Companies (ESCOs) work with energy consumers to reduce their energy and utility bills (often including natural gas and water).

Value proposition: *Consumers can reduce their energy bills (which may include electricity, natural gas, and oil) and environmental impacts through energy efficiency programs operated by the ESCO. Some ESCOs serving larger customers may help with the procurement of energy or risk management.*

- Distributed Solar PV Developers install, maintain and/or finance solar photovoltaic (PV) solar equipment. Three basic variants of this business model are used to provide this equipment and these services. These variants are leasing with third party ownership, site host ownership and solar project development.

Value propositions vary with the business model:

- Leasing with third party ownership. *The customer can generate and consume solar power with no money down and then lease the PV system with a monthly payment that is lower than the cost of buying electricity from the local utility. Solar PV is a hedge against rising electricity rates.*
- Site host ownership. *The customer can receive all the direct financial benefits of ownership, if the customer qualifies. Solar PV provides a hedge against rising electricity rates. On the other hand, the customer must finance the PV installation. Favorable financing terms may be available through the distributed Solar PV developer or other financial institutions.*
- Solar project developers. *Depending on the customer, the electricity purchased will fulfill a regulatory mandate such as a RPS, or a business or personal commitment to sustainable energy. The customer may also, depending on the specific financial arrangements with the developer, become a full or part owner of the PV facility and obtain a share of the financial incentives.*

2. Business Models for Future Markets

TE markets will likely alter the behavior of many electricity consumers and thus change the business models of the organizations in the electric marketplace. For most, revenues will no longer be based on cost of service but rather on the ability to create and capture value. The needs, priorities and decision-making characteristics of consumers will determine their willingness and ability to participate in electricity markets as prosumers in aggregations of consumers. Effective business models will thus need to anticipate and be responsive to ongoing patterns of value creation and destruction, how they differ among customers, and how these behaviors change as markets evolve.

Some business models may evolve from long-standing current business models; others may be created specifically for transactive markets; and still others may have started in earlier stages of the electric markets, but may blossom in TE markets. In addition, with TE markets, electric distribution would change considerably—and in more ways than just facilitating the two-way flow of electrons. Several new and as-yet hypothetical business models would also be essential to the operation of a transactive marketplace depending on the market design.

Each of the retail TE market structures described in Chapter 2 will enable somewhat different sets of business models. The TeMix retail market with its two-way subscription tariff and automated bilateral transaction platform is designed to enable peer-to-peer transactions, and the business models that either enable or can participate in such transactions will emerge. Both the LMP+D and DMP approaches involve bidding into a centralized market operated by a Distribution System Operator (see below) with variable pricing based on models and/or markets. Entities that can best navigate these complex commodity-type markets will best thrive in them. The 3 P's marketplace will create businesses that are structured to respond to and contract under the various pricing, programs and procurements that will be created under this market structure.

New business models will emerge to serve consumer needs in TE markets and others may change to meet the needs of those markets. Some new market participants will likely be customers or aggregations of customers that supply electric services to the transactive marketplace:

- Prosumers would be the most fundamental building block of the transactive marketplace. These are end-use electricity consumers who both buy and sell electricity while interconnected to the distribution system. In most cases, they would generate power through distributed generation. Some could also have energy storage.

Value proposition: Participation by prosumers will result in an electric system that is lower cost, more resilient and cleaner. Who benefits as a direct customer of the prosumer will depend on

the design of the TE marketplace, specifically whether there is a centrally-operated market or bilateral transactions.

- Distributed Energy Storage is a category of prosumer whose primary resource is energy storage. One variant may be owners of electric vehicles.

Value proposition: Energy storage would reduce costs and increase the reliability of electric service to the prosumer. Distributed storage has the capability of providing a flexible resource that can be used for a variety of applications balancing electricity supply and demand on the distribution grid.

Prosumers can combined their operations in varying degrees of aggregation and integration. In increasing order of tightness of integration, these would be:

- Prosumer aggregators simply combine the resources of different prosumers to get a better deal as part of a larger group and take a fee for this service.

Value proposition: Prosumers can receive a higher price for their output as part of a group. Aggregators can better ensure correct payment and knowledgably relieve the prosumer of any administrative burdens. This also may make it easier for buyers who need to deal with fewer sellers.

- Virtual Power Plant Operators coordinate dispatch of the disparate prosumer resources. By making and keeping commitments of availability to the grid operator, the virtual power plant operator may also create value that may be recognized through a capacity payment.

Value propositions: To owners or operators of DER: greater value can be received by being part of a VPP. To wholesale market customers: VPPs can appear to be a single resource to the transmission operator and wholesale power market. The VPP can provide reliable wholesale power products competitive with those of real power plants.

- Microgrids will probably be the most complex and varied of all these new business models. Microgrids combine a group of interconnected loads and supply and demand resources within clearly-defined electrical boundaries that operate as a unified system. Microgrids are typically designed specifically for the host site and vary greatly in their internal loads and the supply and demand resources. The microgrid is operated as an integrated system and has the ability to operate either in a grid-connected or islanded mode. In addition to providing services to loads within the microgrid system, microgrids may also provide electric services to the broader distribution or transmission grids. This gives the microgrid the ability to continue operating when the distribution grid is interrupted. Advanced microgrids contain all the essential elements of the large-scale grid, including the ability to balance electrical demand with sources, schedule the dispatch of resources, and preserve grid reliability, and can operate as an integral part of the overall electric grid. Nested microgrids would operate in close proximity to each other on the distribution network and could be mutually-supportive, possibly with

the ability to reconfigure the interconnections of loads and resources among the microgrids, adding further resiliency to the total system and to the grid as a whole.

Value proposition: *Microgrid customers will have more reliable and resilient electricity. Advanced and nested microgrids may provide further resilience for internal loads and the grid, including compensating for variable resources and providing ancillary services to the grid. Microgrids are most commonly implemented where resiliency is highly valued, for example, military bases or to provide vital community functions. Clean energy and cost reduction may also add value. Some serve island or remote communities, for example, in Alaska.*

With the emergence of TE markets, electric distribution would change considerably—and in more ways than just facilitating the two-way flow of electrons. It would involve new functions and possibly the allocation of functions to different entities depending upon the market design. Each of these entities would need a viable business model. These may include:

- Transaction Platform Provider provides an electronic platform to communicate buy and sell offers in the TeMix markets as well as record the transactions among the parties, including payments. The transaction platform provider may also optionally provide a market clearing and settlements function. More than one transaction platform provider may operate in a market.

Value proposition: *The transaction platform provider provides a convenient and cost-effective electronic venue to find buyer and seller counterparties on the distribution grid, make and record transactions with them, and coordinate with the distribution system and intermediaries.*

- Market Maker would be an independent entity that provides market clearing and settlements to parties that buy and sell in the transactive marketplace. This type of entity may or may not emerge in the LMP+D or DMP markets depending upon how they are structured.

Value proposition: *Payment by buyers to sellers is assured and possibly later liquidity and risk management may be also assured in a peer-to-peer market. Liquidity could only be assured once adequate volume is reached.*

- Distribution System Operator (DSO) is analogous to the ISO or RTO in an organized wholesale electric market. This is likely to be a regulated entity that would be funded based on fees charged to market participants. The DSO in some market designs may be different from the Distribution System Owner.

Value proposition: *The DSO will operate the transactive energy market and other functions assigned to it in a nondiscriminatory, transparent and effective manner that will benefit all those who buy and sell in the transactive energy marketplace.*

- Distribution System Owner (DO) plans, owns, operates and maintains the distribution system in market designs in which the DSO does not also own the distribution system.

Value proposition: *As a regulated business independent of all other interests, the DO will conduct business serving customers in a fair, effective and least-cost manner as regulated by state public utility commissions.*

3. How Business Models Will Change

TE will not materialize overnight and neither will all the business models that support and operate in these markets. Rather, they will emerge as conditions that enable them are created along three mutually-supportive pathways: technology penetration, government policy and regulation, and economics. Emergence of these markets will change the risks faced by those who conduct business in the electric sector, creating risks for some and reducing it for others.

Many factors are likely to influence business model decisions, but this is uncharted territory in a highly-complex, capital-intensive and vital industry. Developing viable industry structures and business models to support these intricate new markets will take time and experimentation.

Developments along each pathway create the conditions that enable markets and business models:

- *Technology Penetration.* A fundamental question is whether consumers will invest in and operate DER technologies as well as participate in a transactive market. Enough market participants must use the technologies to be buyers or sellers in a reasonably liquid market and they must receive enough benefits to continue market participation. This will not happen all at once and simultaneously throughout the country. Uneven progress may give competitive advantages to those that successfully compete in early markets and use these markets as a base for entering later markets.
- *Policy and Regulation.* Many policy and regulatory questions will need to be resolved state by state. States will likely make different choices in creating a market at the distribution level, if at all. No state as yet has a market that can truly be called transactive. Market designs and regulations need to accommodate change over time to improve market performance, to increase participation and to ensure adequate functionality as needed improvements are identified.
- *Economics.* Transactive energy markets are intended to create the basis for electricity products and services to be bought and sold based on value to the ultimate consumers. Prices are intended to be determined by supply and demand and to provide clear value incentives, and the market conditions determined in part by market designs must permit this. These markets would need to incent both economically-efficient investment in DER and their cost-effective operation. Further, these incentives should relate fairly to incentives for large-scale facilities on the transmission system. This implies a need for both long-term market signals for efficient investments throughout the entire electric system in addition to short-term market signals for dispatch.

The business models presented in this chapter are not meant to be definitive. Others may emerge as markets are actually implemented, perhaps even hybrids of those presented here. Rather these business model concepts are intended to begin a conversation on how viable economic entities will actually flourish in TE markets.

Chapter 4: Transactive Energy Models Overseas

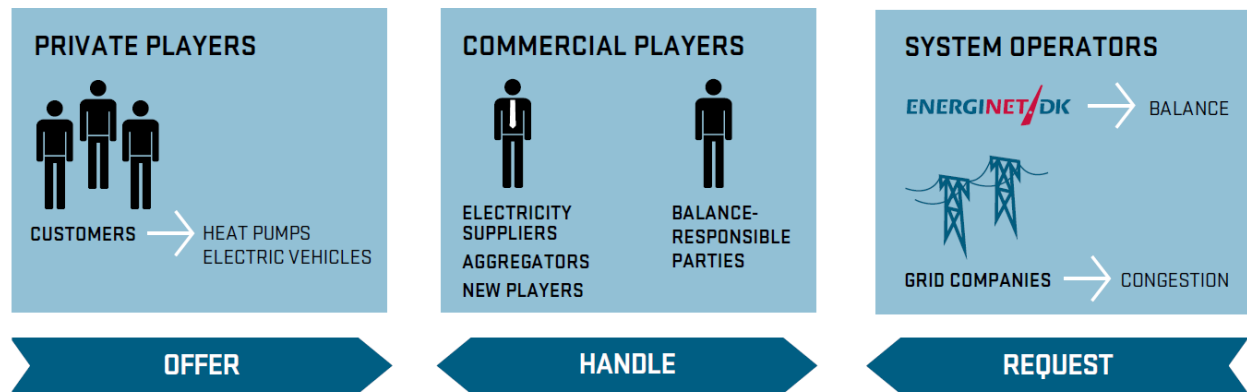
A number of foreign countries have been exploring their own versions of transactive energy models. The following are examples of some who have done significant work in this area:

1. Denmark

In 2010, the Danish government established the Smart Grid Network, which was tasked with preparing a set of recommendations that would enable its electrical grid to handle 50% wind power by 2020. A report was released the following year which provided 35 recommendations for making this transition possible. Together, these recommendations comprised a vision for the evolution of a “market for flexibility” which will encourage third parties (electricity customers) to provide distributed energy resources, when needed, in response to market signals. This will be a transactional electricity grid, in which “flexibility products” will displace the need for conventional grid reinforcements. Such products will essentially consist of real-time demand response, along with on-demand electricity supply and ancillary services being provided at the distribution system level, from behind the customers’ electricity meters.

Roles and responsibilities within this transactional grid will essentially be divided among three sets of principal players: 1) “Private players”, which will include conventional small and large retail electricity customers, along with industrial customers and electricity producers, who will provide flexibility products and services from CHP units, solar or wind resources, electric vehicle charging devices, heat pumps, back-up generators, and demand response (including automated demand response at the appliance level). 2) “Commercial players”, consisting of “balance-responsible parties” (BRPs), conventional wholesale electricity providers, and aggregators, who will essentially act as intermediaries between the smaller private players who are providing flexibility services, and the entities responsible for overall system operation. 3) These aforementioned entities, the “System operators”, will include Energinet.DK, the organization which currently owns and runs the transmission grid, and the local distribution companies, which will still bear responsibility for ensuring system reliability.

ROLES AND RESPONSIBILITIES



The Smart Grid Network plan envisions that the evolution of a new market for flexibility will occur in three phases:

1. **Bilateral Agreements:** Initially, only a few customers will offer flexibility resources, and because of the absence of a fully-developed market, these services will be provided individually, in individually-tailored rather than standardized contracts
2. **Establishment of Marketplace:** Eventually, a market will evolve where local distribution companies can post their flexibility requirements, with the assurance that these requirements will be met. This marketplace for flexibility, however, is not envisioned to operate like the traditional electricity markets in Denmark (and organized electricity markets in the U.S.), where most participants supply bids for supply and demand to a central body, which then determines a market-clearing price for all sales. Because of the diversity of flexibility products offered, and the diversity of needs at the distribution level, it is anticipated that the market for flexibility will be a bilateral one, with no central clearing house, but rather a market in which all transactions occur between individual parties.
3. **Standardization of Market:** In the final phase, well-defined and standardized services and contracts will have evolved, which will enable the efficient trading of a high volume of flexibility services.

The plan includes recommendations for other changes which will support this transition, such as a redefinition of the regulatory compact with local distribution companies that will encourage investment in smart grid technologies, and the establishment of new electricity tariffs that will enable hourly pricing and contract settlement. The current timeline for the evolution of this new system is targeting completion of all technological upgrades and implementation of supporting systems by 2019.

2. Canada

In Ontario, Canada, a variety of demand response programs are in place which together constitute a transactive energy program widely available to all customers. Larger customers and aggregators can actively participate in demand response by offering dispatchable loads, which are curtailed when real-time prices exceed some pre-specified level. Very large companies and institutions (i.e., with electricity usage greater than 250,000 kWh per year) pay the hourly market price for electricity, and react to swings in price by adjusting their loads. Residential and small business customers, too, react to price differentials through time-of-use rates, with higher prices during peak periods and lower prices during off-peak periods. Residential customers also have the option to participate in a special program in which their air conditioning and water heating loads are cycled down during periods of peak demand. The existing Ontario program has had a tangible impact on customer usage, as evidenced by a recent survey in which 70% of Ontarians said that they had modified their electricity usage as a result of having time-of-use rates. Going forward, Ontario's Independent Electricity System Operator (IESO) is engaged in twenty demand response pilot projects with five companies to explore how this wide variety of resources – which together comprise a total of 85 MW of system load – could each best be used to balance supply and demand. The IESO also began, in late 2015, to hold demand response auctions, which will enable the establishment of more flexible, market-determined demand response commitments.

3. Japan

Japan recently completed a series of electricity market reforms that has unbundled transmission and distribution from generation and retail services, and liberalized the retail services sector by opening it up to competition. While these moves may merely result in a system comparable to the organized electricity markets in the U.S., it appears that the reforms have already produced an interest in the sales of electricity by small suppliers, many or most of whom will rely upon clean, distributed energy resources such as solar or wind. As of late last year, nearly 800 companies have successfully registered to become electricity sellers to large commercial customers (>50 MW), and 48 have successfully registered as retail providers to residential and smaller commercial customers. Other companies, such as real estate businesses, are exploring new business models in which homes will be sold with rooftop solar, storage, and/or home energy management systems included, and power will be aggregated and resold from larger-scale distributed energy resources. Consumer cooperatives are also developing locally-generated clean energy power systems for their customers. Though they did not directly result in a transactive energy system, it appears that Japan's recent electricity reforms is laying the groundwork for the eventual evolution to such a system.

4. Germany

In Germany, “virtual power plants” have become widespread as sources of distributed power generation. A “virtual power plant” is a set of independent electricity resources and curtailable loads that are linked together through a computerized control technology and then collectively used to provide services to the general grid. The German electric company RWE Deutschland AG has been selling the services of a virtual power plant into the Energy Exchange (EEX) located in Leipzig. Next Kraftwerke, an IT-energy company, has a virtual power plant consisting of thousands of renewable energy sources, and uses it to sell balancing energy to Transmission Service Operators in Germany. Other companies, such as LichtBlick, are developing virtual power plants that combine electricity storage with intermittent renewable energy sources, thus enabling them to function as price-responsive dispatchable resources.

5. Australia

Companies in Australia are also engaged in the development of systems that combine intermittent renewable electricity sources with storage, and one utility, Ergon Energy Retail, is experimenting with the concept of using these to create a virtual power plant. The Australian electric industry in general is participating in the development of a long-term plan for grid modernization, motivated, among other things, by the fact that there are now nearly two million small-scale renewable energy facilities on their systems. The industry envisions four alternative futures for the grid by 2050: 1) a “set and forget” environment in which the centralized model still predominates, though with more distributed and renewable resources on the system, 2) a customer-centric, prosumer-driven, decentralized and transactive grid, 3) complete abandonment of the grid by customers who now produce their own electricity or get it from local sources, and 4) a system with a heavy penetration of renewable resources, though most of these are large scale, and can be operated with a centralized system. While not selecting any particular outcome as definitive or even most likely, the industry believes that some trends will occur in any case. The system will become more customer-centric, decentralized, decarbonized, and deregulated, but the grid will probably continue to play a critical, though evolved, role.

Chapter 5: Conclusions and Next Steps

The purpose of this paper has been to discuss the transactive energy phenomenon, including the drivers that have been supporting its emergence, the principal models that have emerged that could serve as platforms for creating workable transactive energy systems in the U.S., and the business plans that would provide suitable incentives for all of the necessary entities to participate in these systems. The two transactive energy models discussed in this paper represent alternative means of managing a significant presence of distributed energy resources on the electricity grid. Which of these, if either, will be adopted, will be contingent upon a number of factors. The first, and probably most important, factor will be the actual saturation level and saturation rate of these resources. At present, independently-owned resources are almost exclusively either small scale sources of electricity, such as solar panels, or combined heat and power facilities. If these continue to be effectively managed under the traditional regulated distribution utility paradigm, with perhaps some upgrades in communications and control technologies to better facilitate this management, then the perceived need for a transactional paradigm will be minimal, and its cost difficult to justify. Within any control area where this is the case, only a pronounced commitment on the part of the state regulatory and/or legislative bodies will make the adoption of a transactive energy system possible. Many such organizations that have been engaged in exploring these systems have begun to discover that the “devil is in the details” when trying to develop concrete implementation plans. However, the architects of these systems are continuing to improve their tenability by both developing more detailed and tangible roadmaps on how to “get from here to there”, and also by incorporating new technologies that make these systems more manageable, and less expensive to do so, both in terms of capital and operating costs. Another factor that will contribute to making the adoption of these systems more feasible is the “grass roots” development of islands of transactive energy, most notably microgrids. Aggressive clean energy goals will also provide a tangible boost to the attractiveness of their adoption. And finally, a critical catalyst for more widespread adoption will occur when some state (or perhaps some foreign country) actually succeeds in putting one of these systems into place, and then demonstrates its viability. The evolution of America’s electricity system – particularly its legislative and market models – has always been spurred by the existence of fifty independent state “laboratories”, with certain states taking the lead in exploring and implementing new designs, and when these designs have been proven to be successful, they become templates for similar innovations and even transformations in other states.

A critical element that was not discussed in detail in this paper is the regulatory systems – both federal and state – that will be required to effectively support transactive energy platforms. This element will be discussed at length in Part II of this work.