The Policymaker's Toolkit

Vital Questions to be addressed about Proposed Transactive Energy Systems

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Introduction

The Policymaker's Toolkit was created as a part of the NIST Transactive Energy Challenge, which was begun in March 2015, to: "identify and advance modeling and simulation tools and platforms that can support analysis of TE systems, to raise awareness of the potential benefits of TE, and to build a community that can work toward applying knowledge gained to TE demonstrations". As a part of that initiative, an interdisciplinary working group was formed to explore and describe business and regulatory models that could support transactive energy systems. In September of 2016, that group published a report entitled "Transactive Energy Models" which 1) summarized the drivers of transactive energy, 2) described two alternative transactive energy structures, 3) discussed business models that could support a transactive energy system, and 4) provided an overview of transactive energy systems currently being used or explored by other countries.

The present paper, while essentially a sequel to "Transactive Energy Models", approaches the subject in a markedly different fashion. This paper presents several questions that regulators, legislators, and other policymakers will have to contend with if they are confronted with plans or proposals to adopt a transactive energy system. Many if not most of these questions do not have simple, definitive answers, and in these cases the paper provides advice to policymakers on how to develop suitable answers that can guide their plans, as well as their overall decision to proceed with the proposed system or not.

The questions have been grouped into the following five major topic areas:

- Why Transactive Energy?
- Managing the Transition to Transactive Energy
- Market Design
- Ongoing Market Monitoring and Evaluation
- Consumer Protection

These questions are not exhaustive, and it is the intent of the authors to revisit them periodically – based upon feedback from users of this report – by providing additional questions and refining the answers or guidance to the existing questions. It is the hope and intent of the authors that this document will be a valuable resource for policymakers who face the potentially daunting task of determining when and if a transactive energy system is appropriate for the electricity system within their jurisdiction, and how such a system can be most effectively, safely, and equitably implemented.

Why Transactive Energy?

What operational/electricity power system objectives or challenges would justify the establishment of a transactive energy system and why/how should States consider transactive energy as a pathway for grid modernization?

In responding to a rapidly changing energy landscape, state utility regulators and stakeholders should evaluate the cost-effectiveness of developing a transactive energy system framework. The nature, scope and pace of the changes that are creating new demands, challenges and opportunities with respect to the electricity system warrant examination of transactive energy systems as a future pathway for utility and power system reform, with the objective of fostering an efficient and reliable power system that would support sustainable economic development and social welfare.

Technology, policy and market drivers are converging to create a "sea change" in our energy landscape. Digitization, automation and distributed energy technology advancements; increasingly stringent policy mandates for intermittent utility scale and distributed renewable energy development and energy efficiency; and changing customer expectations, needs and interests (including power system resiliency to natural and man-made disasters and disruptions, choice and heterogeneous needs) together are fundamentally altering electricity sector dynamics: Proliferating renewable, distributed energy and demand-side technologies are creating many new points of power injection and withdrawal, yielding "variability" at the edge of the grid. Policy mandates and directives are stimulating increasing investment in smaller scale, modular, onsite generation and demand-side technologies that are putting pressure on the legacy power system to decentralize and to not only interconnect more efficiently, but also, to integrate these new resources arising at the utility distribution system level. These developments, in turn, are provoking a new stream of market players (proactive consumers and prosumers, aggregators, a range of energy service providers, systems integrators and other third parties) to provide electricity-related services to small residential and commercial customers, in addition to larger commercial and industrial energy consumers.

Within this context of exponential change, there is a growing recognition that a new "utility paradigm" needs to be shaped with new parameters, players and structures -- one that taps into "smart grid" technologies (advanced information, communication and control technologies) to expand electricity value chain parameters (integrating new resources and technologies); and to foster the participation of new market entrants at the bulk power and distribution operation levels. This new utility paradigm will need to be supported by new regulatory incentives and structures that fundamentally change the utility business model to achieve new policy objectives, while maintaining reliability, safety and affordability, in providing electricity services.

Within state utility proceedings, discussions have gone beyond "Grid 2.0" to "Grid 3.0" visions, calling for steps and measures to develop an "Integrated Grid" which can fully take into account and value distributed energy resources ("DER") in utility planning and investment decision-making, operations and market-trading. This emerging Grid 3.0 Vision anticipates tapping into "smart" information, communications and control technologies in order to realize the fuller value of distributed resources and the macrogrid, through evolving an interactive, flexible and innovative grid for the 21st century and beyond. The Grid 3.0 would be characterized by highly flexible, configurable and interactive networks of utility, customer and third-party applications; market data, price signals and transactions; "System of Systems" operations for DER integration and load-side management; and all electricity resources being treated as primary resources. State Utility regulatory and other related proceedings (e.g., "Smart" community development within an "Internet of Things"-enabled transactive framework) are vetting grid designs that would increase the independence, flexibility and intelligence for optimization of energy use and management within local energy networks (running from building, community to distribution system levels) and would integrate local energy resources (supply and demand assets) into a Smart Grid. Integral to this vision is tapping into the fuller potential of "smart" technological capabilities to expand and modernize electrification from source to sink; enable bi-directional power, information and transactional flows through end to end "interoperability;" and allow customers to benefit from dynamic pricing and distributed energy.

In light of these trends, it is important that State Utility regulators and stakeholders evaluate and assess "transactive energy systems" among the "Future Utility" reform scenarios that are helping to shape their agendas. In this regard, States and stakeholders should address the following factors and areas:[1]

Principles and Core Objectives for Grid Modernization – Overarching principles and core objectives should be agreed upon to guide state grid modernization efforts and to compare the cost-effectiveness of "transactive energy systems" with other future scenarios/pathways. These principles and objectives should be grounded in sound economics and bounded by the physical laws of electricity (achieving an efficient means of allocating electricity and other related services, consistent with grid constraints). Transactive energy systems should be evaluated and compared with other possible scenarios based on principles governing the economic viability of electricity systems.[2] An important objective of retail markets in a "Prosumer Future" should be end-users making efficient decisions regarding the usage of, and investment in, local devices, appliances and technologies, along with efficient and appropriate insurance against risk.[3]

Defining and Relating "Transactive Energy Systems" to Grid Modernization – States will need to understand what "transactive energy" means and how "transactive energy systems" would support their grid modernization strategies, based on the GridWise Architecture Council ("GWAC") definition, as well as definitions that have been provided by other organizations such as the Transactive Energy Association ("TEA") and NARUC.[4] Transactive energy will involve the development and identification of

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[1] The discussion includes considerations raised and addressed in "Transactive Energy: A Surreal Vision or a Necessary and Feasible Solution to Grid Problems?" by Atamturk, N. and Zafar, M. of the California Public Utilities Commission Policy & Planning Division (October 2014) (hereafter, Atamturk, CPUC, on "Transactive Energy").

[2] For example, economic viability will require sufficient numbers of participants to provide a level of services that is greater than or equal to the legacy system; Level of services to be provided at a cost that is less than or equal to the conventional system; Value of incremental services greater than or equal to the incremental costs. (See, Caldwell, John, Edison Electric Institute, "The Transactive Electricity Grid," Transactive Energy Summit, Portland, Oregon, 2016)

[3] Efficient Usage is based on the decision to produce or consume electricity locally up to the point where the marginal value of the last unit produced or consumed locally is equal to the marginal cost of producing and transporting an additional unit of electricity over the network to that location; Efficient Investment results from a decision to invest in an electricity producing or consuming device, application or system only if the (forward looking) additional economic surplus created at the times when the device/application/system is producing or consuming exceeds its fixed cost.

[4] GWAC: "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;" TEA: "Transactive Energy engages customers and suppliers as participants in decentralized markets for energy transactions that strive

services sought by utilities, third parties or customers, and value streams available from customer-sited resources (Demand Response, Energy Storage, Solar Photovoltaics, Electric Vehicles, etc.) that are interconnected and interactive with the grid. Transactive Energy Systems ("TES") would support regulatory reform that focuses upon long-term, customer "value creation," as distinctive from the "grow and build-out" orientation of the current regulatory regime.

Assessing Power System Operational Issues Arising from the Increasing Market Penetration of DER and Variable Energy Resources (VER, Intermittent Renewable Energy Resources) – State regulators and stakeholders will need to evaluate the impacts of increasing volumes and diversity of DER and VER on grid operations, both at the bulk power and distribution operational levels; and to formulate and evolve mitigation and control strategies that can minimize adverse impacts and costs and maximize performance and benefits for the grid and its customers. The cost-effectiveness of TES should be evaluated in connection with analyzing these impacts and determining strategies to capture the net benefits that distributed, demand-side and variable resources can offer to the grid, customers and society.

Operational issues at the bulk power level that are stressing the traditional system include: the need for higher levels of ancillary services to mitigate large variations in intermittent renewable energy resources and new types of grid services, such as flexible ramping and loads following; the need for synthetic damping and synthetic inertia to deal with lower levels of conventional prime movers that reduce system inertia; challenges to the traditional methods of bulk power system planning and real-time operation (that are based on the use of conforming load distribution factors), arising from the variability of DER invisible to bulk system operators and their impact on net load variations under a transmission substation.[5]

The traditional distribution business model is being challenged by: 1) the operational challenges of increased levels of distributed generation that is causing higher voltage and reactive power variations, potential phase imbalances and reverse power flows, and 2) the revenue challenges arising from self-generation and increased customer self-sufficiency that is affecting utility energy sales and creating the need for other sources of income for utilities to meet their revenue requirements. These developments are necessitating coordination "at the seams" between bulk and distribution levels, with a "distribution-centric" paradigm shift, as well as material shifting in the distribution system and demand-side interface with the emergence of new actors in the marketplace.[6] These impacts warrant evaluating the development of a TES framework for controlling, managing and optimizing DER and VER to provide grid flexibility and other services (e.g., fast frequency response, regulation services, spinning and non-spinning reserves, resource adequacy capacity requirements).

Continuous Technology Innovation and Improvements – States and stakeholders should evaluate the costs and benefits of TES relating to the nature, scope and pace of technological change and the fusing

towards three goals of economic efficiency, reliability and environmental enhancement." NARUC: "Transactive Energy" is both technical architecture and an economic dispatch system highly reliant upon price signals, robust development of technology on both the grid side and the customer side, and rules allowing for markets to enable a wide variety of participants to provide services directly to each other. This "peer to peer" component differentiates TE from other types of valuation methodologies."

[5] Rahimi, Farrokh and Ipakchi, Ali, "Using a Transactive Energy Framework," IEEE Electrification Magazine, Vol 4, p. 24, December, 2016.

[6] Id.

of power and information within electricity systems. Dramatic changes are already underway in terms of increasing "price nodes" within power networks as a result of increasing digitization, automation, and distributed intelligence and data analytics. As "smart" or intelligent devices, applications and systems proliferate, the potential for these nodes and systems to interact with the grid and with each other will concurrently increase, requiring more decentralization and coordination. TES could provide a cost-effective means for maintaining reliability, energy security and resiliency, while increasing efficiency by coordinating the growing numbers of DER and actors and, at the same time, assimilating/spurring continuous technological changes. States need to evaluate the potential capabilities of TES to provide energy and resource-efficient and reliable multi-objective and multi-actor control, coordination and optimization in an ever-changing energy landscape, as well as to effectively navigate and harness competition and increase private investment along the electricity value chain.

Scaling and Control Strategies – The merits of TES also need to be evaluated based on TES capabilities to cost-effectively deal with growing grid and electricity value chain complexities. In particular, states should assess the capabilities of TES to take a "System of Systems" approach, which could simplify and manage complexities through decentralized, security-constrained, market-driven, hierarchical optimization and control of dynamic sets of distributed and intermittent resources. Transactive energy could scale well at all levels of interactions within the electricity value chain, as "it can coordinate decisions across the full spectrum of size and technology. [Transactive energy] works equally well for central power-plant planning and for small home appliance [and home energy systems] operation. It supports competitive pricing and cost of service pricing."[7] TES could provide a cost-effective means for scaling intelligent energy management, running from building to utility service levels, to maximize performance and minimize cost. States and stakeholders need to evaluate how TES could support the development of smart energy networks in which software agents conduct transactions on behalf of their hosts, with power, information and transactions running in all directions. This evaluation could include assessing the merits of TES to attract investment in the clustering of loads within integrated, autonomous systems or "microgrid cells;" connecting the cells into "distributed networked electricity systems" using smart technologies, and then, connecting the local energy networks to the bulk power system. Networked microgrids could allow sharing of generation, controllable load and storage capabilities over wider areas for optimal energy and risk management.

New Distribution System – TES would support and require the development of a "New Distribution System" to provide proactive network management (network planning, investments and operations) to respond to dynamically changing market conditions and manage customer-side resources. This would include changing the traditional role of the Utility Distribution Company into a "Distribution System Operator" to perform "Transmission System-like" functions within an Integrated Grid.[8] States and

[7] Cazalet, E. and Barrager, S, "Transactive Energy: A Sustainable Business and Regulatory Model for Electricity," Introduction (Baker Street Publishing, E-book, 2014).

[8] Such functions would entail: (1) Maintaining reliable distribution system operation with two-way, multi-point, reversible power flows; (2) Integrating and balancing distributed resources and load to shape load profile and peak demand and to enable multi-function DER to provide services to the bulk power system, reducing the need for transmission and generation investments in bulk system flexibility, ramping and reliability; (3) Achieving functional control of DER for real-time balancing and flexibility and services such as reactive power and frequency control to the local and bulk power systems. These responsibilities would, in turn, require better information exchange between distribution and bulk power system operators and defining and managing the Transmission/Distribution interface to reliably and optimally operate the entire power system. (See, Erickson et.al, "Distribution System Planning and Innovation for Distributed Energy Futures," Power Sector, Springer International Publishing, August, 2015)

stakeholders should assess how using a TES framework could help to value system-based investments and operation protocols that could drive distribution utility efficiency and innovation, with a view to shifting from the traditional approach of meeting peak capacity (and building more to profit) to load profiling and optimizing investments; and from measuring megawatts sold to measuring value creation.

Moving from Passive to Active Consumer Behavior – Technology, policy and market drivers are increasingly clarifying the need for retail market development, aligned with the wholesale market, to increase resource and system flexibility; motivate and inform demand elasticity and respond more cost-effectively to customer, system and societal needs. These forces of change are challenging the traditional legacy system assumptions that: (1) customers have little role to play in addressing system needs; and (2) centralized generation and bulk transmission invariably yield cost-effective results. States and stakeholders need to assess how using a TES framework could accelerate the engagement of customers in the marketplace (including building their capacity to respond, directly or through third parties, to price signals and unbundled utility charges), as well as the dissemination of material information to facilitate such market participation. TES envision moving towards more cost-reflective pricing to motivate more efficient energy usage and investment decision-making by customers.

Facilitating Competition through Admitting New Market Players – The transactive energy construct would change the dynamics of market transactions by giving rise to three categories of market actors: 1) Energy Service Providers (customers, producers, prosumers, energy storage, retail service providers); 2) Transport/Delivery Services (transmission and distribution network owners); and 3) Intermediaries (exchanges market makers, system operators).[9] In evaluating pathways for the future, States and stakeholders need to assess the benefits and costs relating to opening market access to a greater range of actors and how using a TES framework could coordinate and optimize decision-making, with increasing reliance on market forces, while still preserving affordability, grid reliability and safety. States will need to compare the benefits of TES as a valuation methodology to alternative approaches.

Design and Implementation of Demonstrations – State and Federal support of demonstrations are crucial to evaluating the cost-effectiveness of TES in comparison to other pathways for grid modernization and to designing transitioning stages. These demonstrations should be designed to address all of the factors and areas discussed above in order to evaluate the cost-effectiveness of TES in leveraging DER (intelligent grid-edge devices, building energy management systems, microgrids, etc.) to provide customer value and solutions; in shaping responsive grid architecture, as well as networked distributed energy system operations; and in facilitating end to end value chain interoperability and integration. Consistent evaluation, measurement and verification methods need to be developed to compare TES approaches; to compare TES approaches to baseline cases and to alternative strategies. In particular, demonstrations should be designed to evaluate the ability of a TES framework to enable a broad range of operational, business and regulatory models within an integrated electricity system.[10]

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[9] See, Atamturk, CPUC, on "Transactive Energy."

[10] See, Price, Jeffrey, Blue Wave Resources, "Rising Power: How Consumer Participation in Power Markets Will Change the Electricity Business," (January 2017).

Managing the Transition to Transactive Energy

What specific legislation/regulations will be required to advance along the pathway to a transactive electricity system?

This is principally a state retail electricity question, although federal electricity policies and rules that govern wholesale markets may play a role. Federal agencies can help by demonstrating best practices and common service standards that may more easily be adopted and integrated by state agencies with consistency. State regulators act within state legislation. State legislation is a political process involving many parties: voters, utilities, interest groups, etc. Importantly, technology changes are creating new self-supply options for many customers that may force the consideration of TE by legislators and regulators.

The importance of this question varies by state as some already may be more accommodative to TE or have more immediate need for encouraging market driven solutions to help balance the growing instabilities of renewable energy. All well-designed markets require laws, rules, and oversight; yet the wrong design can impede innovation, efficiency, and fairness and increase the likelihoods of success or failure.

Financial resources will be needed to support state policy analysis, education and advocacy.

TE, properly designed and implemented, offers the prospect of a sustainable electricity regulatory, market and business environment for all parties including customers, utilities, suppliers and vendors.

The primary focus needs to be on a transition away from rates supported by a legislative mandate, special interest subsidies, and political inertia to one that becomes more reliable and resilient for all parties to the electricity markets. The governing bodies should create market mechanisms that effectively and efficiently reward long-term commercial contracts, self-investment by customers and reliable intermediaries capable of absorbing commercial risk between short and long-term contracts/investments while serving the full range of customers.

The process for addressing legislation and regulatory changes for each state would involve the development of a non-profit and non-partisan lobbying and educational group in each state drawn from interested customer, environmental, utility and vendor groups: This non-profit would assess the needs and develop TE policy proposals and educational proposals for legislators, regulators and interested parties and then work with legislators and regulators to craft legislation and regulations. In addition, rather than pursuing a critical path that relies on completing the legislative action before moving ahead, it is recommended that the state develop aggressive and realistic parallel tracks for experimental demonstrations that encourage rapid prototyping through incumbent utilities, entrepreneurs, and associated research universities.

Who will bear the risk and responsibility of stranded investments? Should this be mitigated, and, if so, how?

Policy makers, regulators, market designers and stakeholders need to consider the risk of potential stranded investments. This is important to consider on at least three dimensions.

First, the cost-effectiveness of transactive market designs should be evaluated. This involves prospective assessment of the value of a market design with the associated costs. Benefits should be weighed against potential failure risks, such as illiquidity, gaming, and poor performance, to develop and expected value. Too often the benefit of market designs, especially with transactive markets do not account for performance risks. The expected value of the market should be evaluated against the costs to implement. Cost estimates should also include contingency based on probabilistic methods to recognize implementation risks. This approach allows decision makers the ability to assess the expected value and cost of implementing and operating a TE market design.

Second, technological innovation cycles are at least twice as fast as the electric industry regulatory-business cycle. This creates a challenge in that transactive energy markets are highly dependent on enabling technology for market platforms, operational integration and settlement. This is compounded by technological advancement of participating distributed resources and related operational systems. These technologies and the associated implementation and maintenance costs are significant and can run into the hundreds of millions to billion plus dollars for statewide deployments. Managing these multi-year investments and related approvals all the while technologies are advancing creates functional and technological obsolescence risk. This friction is like a fast rotating gear meshing with a slow-moving gear – very difficult to mesh precisely.

Third, customers who decide to largely or completely self-supply may leave other customers with the stranded cost burden of paying for generation, transmission and distribution infrastructure previously purchased by regulated utilities to serve their customers.

These risks and others are important to consider in the context of potential market failures and/or implementation decisions that result in large stranded investments. Also, if certain investments become stranded a question arises regarding who should bear responsibility for their costs. This is a complex question given that policymakers and regulators have traditionally assumed that markets benefit all customers and therefore that all customers should pay for and bear all or at least most of the risks. In TE markets, it may be the case that only direct participants in a market may benefit and therefore should bear the costs and risks. It is important, therefore, to clearly identify the beneficiaries of specific TE market designs to assign cost and risk responsibility. This approach is in line with cost causation and cost allocation principles.

To mitigate the potential for market failures and operational risks it is necessary to prospectively assess relevant risks including those described above. For each risk, a mitigation strategy should be developed. One technique to consider is a “pre-mortem” in which failure (or unacceptable outcome) scenarios are developed to better understand the cause and effect of decisions that may lead to failures. In such an approach, a diverse expert group works back from the possible failure scenarios to diagrammatically create potential decision trees that may lead to such a failure. This allows for critical assessment of the actions that may lead to a failure or unacceptable outcome. This type of analysis may also enable assignability of risks and benefits perhaps using forward transactions for both energy and distribution services and risk mitigation via incremental and perhaps lower investment alternatives for TE implementation.

How should infrastructure investments to enable prosumer participation in electricity markets be evaluated, especially when many of these decisions involve new and immature technologies or cannot be supported by traditional analyses?

The creation of TE markets will require numerous decisions about the DER and grid enhancements investments necessary to support prosumer market participation. Evaluations of these investments will need to be made by prosumers and by distribution system owners and some investments may need to be justified to public utility regulators using these evaluations.

The scale of investments is likely to be very large on both sides of the electricity meter, eventually running into hundreds of billion dollars. Such investments could fundamentally transform the entire U.S. electric power system. All this would have a major impact on the nation's economy, welfare, and security for decades to come.

Many challenges are likely to be encountered in making, authorizing, and permitting these investments. Multiple decision makers and varied interests will be involved and their decision-making will be interdependent. Some decisions will be made at the local level, others at the state level, and still others at the federal level. Many decisions will address resiliency concerns for which traditional cost-benefit analysis breaks down because probabilities are unknown or impacts are extreme. Decisions about new and immature technologies are based on expectations about their eventual maturity, which may or may not occur as expected. Moreover, many new (and even unexpected) technologies will compete in a rapidly-evolving marketplace. Many questions are as yet unresolved about what investments should be made, their timing, who should make the investments, and the value and allocation of benefits, costs, and risks. Private-sector investment (including investments in related public sector debt) can be mobilized only when such questions are answered. All these challenges must be addressed by analyses of these investment decisions.

Legislators and regulators will design electric markets. Fundamental issues—including those related to investments—are thus public policy concerns. Effectively addressing these investment concerns will require a robust public debate based on real-world data and valid analyses. Varied legitimate interests and public policy concerns will need to be addressed. Multiple analyses by different stakeholders will be needed. Policy risks can be minimized through well-planned experimentation and sequencing of market designs and investment decisions. Market participants could also face ongoing political and regulatory risks; that is, the market rules will change after the investments have already been made. These risks will also likely be considered.

Making individual investment decisions will require specific analyses for those making the investments. These analyses cannot be traditional utility least-cost or integrated resource planning; such analyses do not apply to transactive marketplaces. Similarly, market modeling typically used to evaluate investments in large-scale generation facilities that operate in wholesale markets do not apply. New types of analyses will be required. These analyses must take into account the as-yet-unknown dynamics of a competitive distribution-level marketplace. New analytical techniques are also needed to address the unique nature of resiliency investments.

Planning for these evaluation techniques must start by taking an inventory of decision and analytical needs and identifying specific gaps in current evaluation techniques, taking into account that work that is already underway. Methods to plug those gaps can then be identified.

How can demonstration projects be most effectively used to support transition to TE?

The new era of Transactive Energy introduces many changes simultaneously to the paradigm of energy production, distribution, and consumption that has been firmly in place since the launch of the industry by Thomas Edison. The regulatory constructs that have emerged over the decades have been evolutionary in nature, addressing the need for a more efficient and cost effective system while assuring reliable universal service, but always centered on a technology approach designed for central generation to distributed load.

Changes to this established order are driven primarily by the rapid advancement of affordable Distributed Energy Resources that are being adopted by traditional energy-taking consumers, to partially or fully offset their electric power draw from "the grid". As an added value, these investments are delivering an added measure of reliability and resilience to the owners of the assets, and are ultimately allowing the highest level of efficiency by connecting source to load with the shortest possible circuit and fewest voltage conversions. With the addition of energy storage at the edge of the grid, there are important balancing services that are possible by intelligently coordinating with the DER. Transactive Energy unlocks the value streams for these services and incents a market-driven solution to drive toward optimal economic efficiency of the solutions.

Demonstration programs can provide a valuable insight into the nature of the systems involved in a Transactive Energy solution that is being considered for a utility service territory, highlight of the potential and actual benefits and costs from implementing these systems at scale, and can expose potential unforeseen consequences. Data collected from these demonstration pilots will support informed debate and decisions on needed legislative and policy changes. Looked at another way, a well-designed demonstration can provide a very high return on investment to the rate payers and citizens within the utility jurisdiction when a proposed move to Transactive Energy is formulated. Here's why:

- A demonstration makes an explicit statement on a desired future state, including hypothesis on expected costs and benefits. The hypothesis can be formed based on factual modeling and simulation work that has been carried out at the national labs, as well as unique local distribution system issues.

- It can be designed to bring many stakeholders to the planning and participation stages within the demo.

- A demo can be designed with a multi-segment and staged component approach, that break the discovery down into more manageable but ultimately integrated pieces. The staging can be timed with the broader progressive arc.

So how best to approach "making the case" for requiring, designing, and funding demonstration projects? The principal considerations driving the regulator's request for these programs are the following:

- Can a local program take up a previous national or regional demonstration and tailor it toward quick validation of local applicability? Can the work be extended to expand the body of common knowledge and best practices?

- What parts of the Transactive Energy paradigm will require the most local outreach, education, and participation because of unique factors in play within my regulatory jurisdiction?
    - Retail competition and local rate pressure
    - ISO/RTO market programs that offer grid service revenue to market participants
    - Development of strong academic Centers of Excellence for grid modernization careers

- How prominent is DER and/or microgrids featured within the local utility's Integrated Resource Plan commission filing? A Transactive Energy demonstration can help the utility evaluate levels of customer-side participation that could be tolerated, and can even help to develop data that supports a stand by tariff.

- Available public/private funding mechanisms

Market Design

Who should be allowed to participate in a TE system? What entities will be necessary to make such a system work? Which stakeholders should be represented to make such a system fair?

State legislators and regulators may set the rules for parties to transact retail electricity with each other. Moreover, the retail parties, in most cases, will decide to participate in the TE system or alternative systems depending on State law.

TE should enable any party to buy or sell electricity products with any other party while paying for necessary common distribution circuit and transmission infrastructure and while observing environmental, reliability, safety and fair commercial practice and laws and paying appropriate taxes and public purpose charges.

Key retail parties and stakeholders include consumers, prosumers (with behind the meter generation and storage), standalone distributed storage and generation, distribution operators/owners, load serving entities including IOUs, municipals, community choice aggregators (CCA), wholesale generator owners, storage owners, and power marketers, energy management service and technology companies, advocacy groups such as environmental, specific income and political groups, etc., and governmental agencies.

Additionally, wholesale parties will have a role in transactive retail markets at the wholesale retail interfaces including transmission owners and operators, and wholesale generators, storage, large wholesale customers, wholesale power marketers, federal and state agencies and IOUs, municipals, and public power utilities.

Legislation and regulatory changes and oversight will be required to implement TE.

Technology such as real-time interval metering, low cost, convenient wireless network and device control, modular generation and storage systems are enabling TE. GHG, other environmental and resiliency needs, renewables, and interest from customers are driving the trends to TE.

A key consideration is whether the distribution operator will operate a centralized locational market on the distribution circuits and dispatch distributed resources including demand response or whether a separate set of automated forward and spot bilateral TE markets supported by automated market makers will be used.

A decentralized bilateral TE system requires a TE Platform operator, a conventional distribution operator to own and operate the distribution circuits, and self-dispatching parties such as end customers, distributed generation and storage owners, 3rd party intermediaries, and wholesale participants in retail markets. A centralized locational market requires a distribution system operator (DSO) to operate a market and dispatch significant resources owned by the various parties.

What must be done (e.g., establishing uniform contracts) to enable competitive trading of bilateral contracts?

Bilateral contracts represent the vast majority of transactions conducted in power markets. While real-time markets conducted by ISO/RTOs get a lot of attention, their markets actually only represent about 5% of transactions in their areas. These ISO/RTO markets include residual energy transactions based on changes to previous bilateral contracted energy between two parties. In effect, bilateral contracts are the primary means of transacting in the power industry. As such, it is important to TE market development that barriers to participation be reduced to improve liquidity and sustainability. Uniform, standard contracts along with uniform market rules nationwide are foundational.

Enabling competitive bilateral contracts for energy and others services at the distribution level may require – in addition to the market participants themselves – the engagement of state regulators, NARUC, FERC, ISO/RTO, the North American Energy Standards Board (NAESB), depending upon whether the wholesale or retail/distribution market is involved and on the types of transactions. For example, transactive bilateral contracts may involve the provision of wholesale ancillary services which are governed by federal regulations and for areas managed by an ISO/RTO these contracts may also need to comply with specific market rules. Over-the-counter energy transactions between two independent parties are governed by FERC power marketing rules and typically utilize NAESB standard contract terms and conditions.

Transactions between DER service providers and distribution grid operators will require development of standard contracting terms and conditions as well as defining standard definitions of services to facilitate market animation. These pro-forma contracts will require state regulatory review and in many cases uniformity across a state. Ideally, NARUC could coordinate ratification of a national standard contract, perhaps in conjunction with NAESB.

Bilateral energy transactions across the distribution will involve state regulatory oversight and possibly FERC. States may need to adjust/create power marketing rules from those used to resell wholesale energy to retail customers. In the new context, transactions may look like wholesale in that they do not involve retail customers. So, rules and contracts may benefit from adapting FERC power marketing rules and NAESB standard contracts. However, it is also possible that prosumers may look to contract to sell power to a reseller such as an energy services firm or community choice aggregator. In these cases, it may be the state regulator that should develop governing rules that include consumer protections, along with standard contract terms and conditions. Again, these rules and pro-forma contracts may be able to adapt preexisting references from wholesale markets and bilateral transactions between services providers and utilities.

NARUC may be well served to form a working group to begin the process of assessing the immediate transaction types that states should consider in the development of standardized contracts. Today, that may involve DER distribution grid services as non-wires alternatives being implemented in several states. This working group would be comprised of knowledgeable regulatory staff, NAESB representatives, utilities, market participants and consumer advocates as well as other stakeholders.

How should distributed energy and unbundled services be valued and priced?

Two related fundamental economic questions face the legislators and regulators who will design TE markets: (1) how will the value of the DER resources be established (recognized); and, (2) how will market prices be determined (rewarded). These are complex and sometimes highly-contentious issues. Why is this important: Having these methods properly defined and vetted are critical to unlocking the latent private capital investment in, and securing the fully engaged participation of, an optimal mix of DER for the modernized grid.

Alternative approaches exist for answering both questions and different methods may be used to calculate value and price under each alternative approach. Price equates to the cost of electric service to buyers and also determines the revenues of DER providers of that service, thus setting up opposing viewpoints. One element of the price of electric service to consumers is the cost of distribution service, which will likely continue to be regulated. Estimates of the cost of distribution service, however, must take into account new considerations such as two-way power flows, congestion over different portions of the distribution grid, attributes of resilience, and the grid investments needed to enable TE transactions. How those new costs will be allocated must also be decided.

The value of DER to buyers depends on their specific needs for electricity and other, perhaps intangible, considerations (e.g., the desire to purchase renewable energy). They will buy when the value they place on electricity (perhaps from a specific type of source) exceeds the market price. Sellers will need prices that exceed their full costs for investments and variable costs (zero for some technologies) for operation. The value of DER to the sellers will be the margin they earn from the DER. Their costs for new DER will change as technology evolves. Governments may also add a social value on different energy sources, such as solar, or on various types of performance (e.g., flexibility, availability, zero carbon). Various components and different methodologies may be used to estimate this social value and market designers must choose which, if any, should be used.

Prices in a TE market will be determined by transactional decisions of both buyers and sellers under the market pricing mechanism specified by the market design. Several types of pricing mechanisms have been proposed for DER markets including variations of: (1) bids by prospective sellers of DER services in a reverse auction by a utility; (2) matching sellers with buyers in a two-way auction; and (3) a centrally-operated market where prices are set by a constantly-updated market model. Each pricing mechanism has its advocates and opponents. Each also requires a communications infrastructure for bidding, selection, dispatch, and audit of the DER services. Prices under each of these mechanisms may take into account overall electric market supply and demand conditions, where the DER is located in the distribution grid, reputation of the seller, and a social value taking into account externalities.

One further consideration is how values and prices in the electric distribution market in which DER participates relate to values and prices in the wholesale electricity market. Aligning these two sets of prices may involve interactions among state legislative and regulatory authorities, the Independent System Operators operating the wholesale power market and the transmission grid (possibly covering multiple states), and the Federal Energy Regulatory Commission. An additional and emerging consideration is the nexus of adjacent vital community services such as Natural Gas, Water, and Transportation. These are driving the evolution of Smart Cities solutions.

Value and pricing mechanisms are policy decisions that must be made by legislatures and regulators after study and debate. Considerable analysis and debate has already taken place in states that have been considering TE—California, New York, and Hawaii, for example. Lessons can be learned from these states as well as prior and ongoing TE modeling and simulation experiments and fielded demonstrations.

What tools and services must be available to smaller customers to enable them to participate in the TE market along with larger customers, and derive maximum benefit from the system?

Policymakers and regulators need to consider customer access to participate in transactive markets. This should include the unique circumstances for different customer segments. Much of the transactive energy discussion has implied a relatively sophisticated commercial or residential customer, perhaps represented by an energy service provider. While larger customers use a greater amount of energy, their numbers are very small. Conversely, smaller customers comprise the vast majority of grid customers. These customers cannot be left behind, akin to the digital divide. As seen with net energy metering and the California energy crisis, they often carry a disproportionate share of the cost to develop and operate such markets, but often don't benefit and carry much of the risk of failures.

For these reasons, it is essential to consider the means for all customers to participate in transactive markets as they may develop. This will include implementing market rules, services and technologies to enable participation. A starting point is to consider the needs of smaller customers, in addition to other customer segments. This should involve several factors, including access requirements, participation costs, any behavioral change, and benefit potential, as well as the consideration of small customer financial settlement needs. For example, a large portion of electric customers (as much as 20%) are considered "underbanked". This term refers to customers that do not have a banking relationship and instead transact in cash and cash equivalents, such as prepaid credit cards.

These types of factors enable an examination of the market design, services and tools required for beneficial participation by smaller customers. This type of evaluation is well suited for a small working group comprised of core contributors including TE market designers, small customer experts, consumer product developers and regulatory staff. This type of working group would be aligned to a specific regulatory proceeding, and the output of the group would inform such a proceeding and the subsequent ruling. Additionally, the working group could inform industry on the services and technology functional requirements

What products should be traded in TE markets (e.g., energy, capacity, Kvar, etc.)?

The products traded in a TE market depend on the design of the market and the extent to which participants are allowed to customize transactions to their needs under that design. Those decisions would generally be made by legislatures and utility regulators. On the one hand, the products may be those typically traded in wholesale markets: energy, capacity, ramping, voltage/VAR (volts-amps-reactive), and frequency regulation. On the other hand, some proposed TE market designs have only a limited set of products: notably only energy and transportation. The functionality of a Distribution System Operator (DSO), as well as its interface with wholesale markets and customers, is critical to define in order to support TE markets.

If a TE market aims to meet customer needs while efficiently utilizing existing wholesale power markets, at least two assumptions derive: First, the efficient use of a wholesale market by a TE market will entail reducing the needs and costs of wholesale products, which will probably result in TE markets actually competing with wholesale products for balancing energy, ramping, and ancillary service needs. Second, at the distribution level, voltage/VAR will probably have to be unbundled.

In order for the TE market to be viable, the products traded in the TE market must reflect both the needs of the buyers and the capability of sellers (those with DER) to provide the products valued by buyers. The buyers may be other consumers, other prosumers, utilities or even other participants in wholesale markets. The capabilities of the sellers will depend on whether they are demand- or supply-side resources (or both), the size (kW and/or kWh) of these resources, and the ramping capability, location, and controllability of these resources. An important decision of market designers is the extent to which the products are to be standardized or subject to negotiation. Are these one-time transactions or longer-term contracts? In any event, many of the "fine print" details of transactions may be standardized in order to facilitate the transactions and protect small market participants.

The need for time-based granularity is relevant. What levels of time-based granularity are needed depend on the products transacted. The CAISO physical market, for example, now trades energy in 5, 10, and 15 minute increments. Operating reserves are also sub-hourly in most ISOs/RTOs. Frequency Regulation and Reg-Up/Reg-Down require much faster response of course.

5 minute granularity for the TE energy product seems desirable, as electricity production at this level is likely to be from PVs and wind, as well as bio-fuel based generation. If this is too granular for market needs, a one-hour energy market may be more suitable. CAISO, for example, asks for instructed energy to be provided, and allocates costs that relate to ramping needs when energy deviations occur. In the Netherlands, where a TE energy market exists, instructed energy is not called for, and average deviations in delivery over the hour are accepted. Absent an instructed deviation approach, the consequence is that TE would not reduce the costs of deviations. On the other hand TE market participants might use a deviation penalty system to provide price signals for uninstructed deviation, but this is complex and requires a more expensive system for settlement.

As the impacts of must-take renewable resources, such as PVs and wind, in front of the meter (IFOM) or behind the meter (BTM) include ramping needs as well as voltage compensation, these products should also be expected in TE markets. Approaches to reduce ramping needs will have direct consequences in wholesale markets, reducing these costs. This suggests that opportunity costs in wholesale markets provide potentially useful proxies for TE market products.

The energy products are transacted at the distribution level, and may also be transacted in wholesale markets. Most expect energy to be traded in TE markets at some level such as hourly, day-ahead or near real-time. In such an event, seams issues between the retail and wholesale markets may need to be addressed.

When confined to a distributed energy framework such as a microgrid, DERs are assumed to be providing for reliability during contingencies and when response to uncertainty is warranted. In wholesale markets, resource adequacy (RA), a capacity product, is currently segmented into system, local, and flexible products. The question then is whether similar products be appropriate in TE markets.

Just as in wholesale markets, where TE cannot provide for uniform trading and custom transactions are preferred, bilateral contract markets will be used. In the context of TE, this raises the question whether a bilateral contracts bulletin board may be used to trade and transact energy, capacity, and related electricity products. The market viability of bilateral contracts is generally preserved by the contested nature of buyer and seller. At the same time, customized, non-uniform, transactions are commonly used. Bulletin boards can be used to publicize the availability of bilateral contract offers.

When will I know that it is time to adopt locational pricing? What will be the justifications for doing so?

Efficient operation of retail markets requires recognition of distribution grid constraints that have locational impacts on transactions. Moreover, alignment of cost allocation and cost causation requires recognition of locational value of transacting distributed energy resources (DERs).

The value of distributed generation, storage and load management for distribution system planning (infrastructure investments) and operation (reliable economic operation) depends not only on the underlying technology, but also their location in the distribution grid. In the planning domain locational pricing is already underway. The DER auction for deferment of investments in Brooklyn Queens (http://www.utilitydive.com/news/coned-awards-22-mw-of-demand-response-contracts-in-brooklyn-queens-project/424034/) and PJM's locational pricing of DERs in forward capacity auctions (http://www.pjm.com/media/documents/etariff/FercDockets/2017/20161117-er17-367-000.pdf) are witness to this move that is already underway.

In the operational time domain, retail bid-based locational pricing like wholesale bid-based locational pricing is further away until such time that there are liquid local transactive markets, if ever. One problem is that current retail distribution circuits may have largely non-dispatchable solar and combined heat and power generation. Although new prosumers may have more flexible price responsive end-use devices, they are not likely to participate in bid-based dispatch in the absence of clear retail market signals that are currently available only through limited demand response programs. Even when such retail market rules are in place, temporary distribution constraints may give rise to perverse bidding behavior. In fact, this is a phenomenon observed in wholesale energy markets as well. Many of the wholesale markets impose rather heavy-handed mitigation rules (including must-offer requirements to mitigate physical withholding, and bid mitigation for economic withholding) to avoid locational market power and gaming due to inadequate locational competition. This situation is much more severe in bid-based operation of distribution systems. So the distribution operator must dispatch cost-based resources at its disposal to overcome distribution constraints without computing and applying distribution locational prices. In fact, the DERs procured in the planning auction horizon (such as Brooklyn-Queens) are generally available for dispatch to the distribution operator at predetermined strike prices.

An alternative to bid-based dispatch retail markets is applying regulated distribution rate adders to wholesale prices at the retail/wholesale interface. The alternatives include fixed adders as currently proposed in New York, adders based on time of use, and two-way, dynamic hourly or 5-minute distribution price adders based on recovering more of the largely fixed costs of distribution circuits when the circuit is more heavily loaded in either direction.

The justification for improved retail/distribution markets will arise first in markets with actual or potential benefits for deployment of distributed generation and storage and potential deferral benefits of distribution circuit investment. In these markets improved retail tariffs should be the primary initial focus with more complex approaches only deployed on circuits when the benefits exceed the costs.

The distribution operators in collaboration with the Local and/or State regulatory bodies need to work together and support demonstrations of the various approaches on selected circuits. The locational resolution may start with the sub-transmission substations (interface between distribution and bulk power operations), and gradually refined to distribution substations, feeders, and even phases (although locational prices per phase will not be realistic for the foreseeable future).

How will the wholesale/retail interface be managed? What boundaries will need to be maintained between these, and by what authorities or entities? Will transactive energy blur the lines between the wholesale and retail markets? Will this present a threat to usurping my authority as a state regulator?

The rise of distributed generation, storage, and customer load management along with a recent set of U.S. Supreme Court decisions has blurred the lines between wholesale markets (under federal authority) and retail markets (under state authority). The development of transactive energy markets may either complicate or simplify these issues, depending on how transactive energy is approached.

In 2016, three major U.S. Supreme Court cases centered on the long-standing split of jurisdiction between the Federal Energy Regulatory Commission (FERC) and the states. These court cases suggest there is no longer a "bright line jurisdictional test" between federal authority in the wholesale market and state authority in the retail market. Distributed solar, battery storage, demand response, electric vehicles, and microgrids are challenging the traditional electric energy system business models and regulatory schemes. The first of these technologies to blur the wholesale and retail regulatory market lines was demand response – the centerpiece of the FERC v. EPSA case before the U.S. Supreme Court. In this case, the power generators in the case challenged FERC authority under its Order 745 – requiring that regional grid operators compensate aggregated bids of demand response at the same wholesale market price paid to generators in the wholesale energy markets.

But this wholesale/retail conflict may be the result of current retail rate design with generally fixed and mostly flat retail rates. Such rates engender demand response programs to buy back energy at peak load times using assumed baselines at wholesale prices higher than retail rates; as a result, FERC now claims some jurisdiction over retail demand response prices – normally a state jurisdiction. These issues are illustrative of the need for some market redesign.

Management of the wholesale/retail interface is both a potential jurisdictional issue as introduced above, but also a market design issue. Can the wholesale and retail markets be designed in a way that allows for relatively independent state oversight of retail markets and federal oversight of wholesale forward and spot markets? Approaches to market design include a) grand central optimization, b) layered decentralization optimization, c) automated decentralized bilateral market, or hybrids of b) and c).

It will take a team from several perspectives to address this issue. Specifically, the team should include FERC, an ISO/RTO, IOU and municipal distribution operators, retail LSEs, direct access customers and aggregators, storage and PV vendors, PUCs, state legislators and retail rate experts and retail and wholesale market designers.

Ongoing Market Monitoring and Evaluation

What are the potential (negative) unintended consequences of transactive energy, and how can the probability of their occurrence be reduced?

Policymakers, regulators and stakeholders need to consider the potential negative, unintended consequences of transactive energy. There are several issues and risks that may create negative consequences for market participants and all customers. Transactive energy is essentially a method to optimize certain aspects of the use, production and transport of energy. As such, TE is an overlay on an already complex power system. This introduces several additional risks beyond those previously identified:

- Randomness (aleatory) risk associated with random variations inherent in the cyber-physical electric system or the markets operated over that system,
- Knowledge (epistemic) risk related to a lack of knowledge (known-unknowns) about the behavior of a greatly-changed electric network with a vastly increased number of connected devices coupled with new and complex market designs,
- Interaction risk created by the interaction between customers, distributed energy resources, markets and elements of the electric network, and
- Black Swan (ontological) risk pertaining to low probability-high impact or unknown-unknowns events occurring.

Although it has changed with the creation of wholesale electric markets operated by ISOs or RTOs, the electric system has historically largely relied on operating margins and conservative engineering design to manage the inherent random variations on the system.

Aleatory risk is rising due to increasing intermittency from variable energy resources and related dynamic interactions between transmission and distribution systems. Transactive energy if not done properly may increase aleatory risk locally and on larger geo-spatial dimensions as networks are balanced through use of DER and use inter-regional generation resources. It is clear that traditional deterministic methods applied separately to transmission or distribution is insufficient. Stochastic modeling and dynamic risk management techniques should be applied holistically when evaluating transmission and related distribution systems.

Likewise, the existing paradigms for power system engineering and design are inadequate for a distributed system with a high degree of **epistemic risk** involving the behavior of millions of independent agents/customers and the response characteristics of their generators, energy storage resources and energy management systems. Deeper situational awareness built upon an effective observability strategy utilizing embedded sensors across the grid and customer resources will allow grid operators better understanding of grid state information to assess reliability and stability risks. However, to manage epistemic risk, policymakers and/or the entities charged with directly managing the grid will need to acquire information regarding the general behavioral characteristics of customers and smart devices and how these both impact and are impacted by activities on the grid.

Interaction risk arises from the increasing complexity of the cyber-physical grid and the transition from a roughly 40-year-old-system to a 21st century electric grid. Transactive energy may involve millions of devices interactive operated by multiple parties for diverse purposes that may not be expected or even known to the system operator. The challenge is that, without an effective set of architectures to guide development, the risk associated with unintended consequences stemming from undesirable interactions will significantly increase. Coordinated decision-making across the transmission, distribution and customer tiers may reduce these risks and should be explored.

Black swan events in the electric system seem to be occurring more frequently than expected. These are of great societal significance due to the human and economic consequences of sustained, widespread, power system failures. The challenge is two-fold; low probability "tail events" do not fit traditional engineering planning models or risk assessment tools and true black swans (unknown-unknowns) cannot be quantified. In his book *Antifragile – Things that Gain from Disorder*, Nassim Taleb attributes the rise of black swans to "the loss of robustness owing to complications in the design of everything." Transactive energy approaches add complexity to an already complex system, creating an even more fragile system. The shock of a black swan event may exacerbate the impact of an event. Past events could be used as surrogates in pre-mortem assessments for TE market designs and systems to assess their relative fragility.

These risks that may lead to unintentional consequences should be evaluated through a pre-mortem exercise to envision the consequences, assess the potential root causes and assess possible mitigation measures. Such an approach may also be useful to assess the riskiness of alternative market designs.

What criteria should regulators use to evaluate the success/effectiveness of proposed or operational transactive energy systems?

Such an evaluation should establish as a baseline the successful hallmarks of traditional electricity regulation: reliable electricity service provided in a cost effective manner to all who want to receive it. Any proposed transactive energy system must not detract from this baseline, and should present the potential to rise above it, in one or more of the following dimensions:

- **Affordability**: While the overall cost of providing electricity service should not increase, opportunities should exist for customers who choose to take a more active role in managing their electricity service to reduce their electricity cost, through the use of distributed energy resources, price-responsive demand, and negotiated interactions with other entities on the grid.

- **Reliability**: Overall system reliability should remain at or above levels that existed under the traditional regulatory model, but customers should have the ability to attain even higher levels of reliability and/or resiliency through such things as energy storage, microgrids, or the use of local energy resources, if they are willing to pay for it.

- **Sustainability**: Mechanisms should exist for promoting clean energy resources which are at least as cost effective as those already in place (e.g., state RPS requirements, national clean energy policies), and ideally more cost effective and economically efficient than these existing ones.

- **Universal Service**: Any transactive energy system must provide sufficient energy resources (both electricity and ancillary services) to enable the continued safe and effective operation of the grid and the availability of electricity to all customers on the grid. There must be no risk of shortages or restricted service due to either the lack of available energy providers or market power abuses by one or more dominant providers. While some customers may voluntarily subject themselves to price risk if there is a potential gain in doing so, customers who choose not to do so should not be exposed to the risk of significant increases in their electricity costs above the level that they would have incurred under the legacy system.

Consumer Protection

How do I protect traditional consumers who do not want any involvement in "transactive" energy? Is there an effective way to derive the benefits of transactive energy for those consumers and prosumers who do want to engage in it, while limiting the exposure for those who don't?

In the design of Transactive Energy System operation and settlement rules, it is important to lay out the ground rules so as to ensure that any distribution system operating costs attributable to Transactive exchanges are allocated to the Transacting entities based on cost causation. In other words, the transactive market design must ensure the rest of the consumers/prosumers who do not engage in transactive exchanges are kept harmless with respect to such incremental system operations and maintenance costs. There are also situations where such bystander consumers/prosumers may benefit from the collective actions of transactive parties. The transactive system design must recognize, quantify such benefits and account for them in computing a total settlement interval net cost (positive or negative) of system operation to allocate based on cost or benefit causation to the Transactive entities.

The individuals/entities who should ultimately answer this question are those involved in transactive energy market design, with the collaboration of the corresponding State and Local regulatory agencies having jurisdiction over the utility operation and cost allocation tariffs and protocols, and the distribution utilities responsible for system reliability.

The distribution system operator (DSO) must operate the distribution system reliably and economically in the face of transactive exchanges with proper recognition of any voluntary bids and offers submitted to it by prosumers. As far as the DSO is concerned any peer-to-peer transactions among transacting parties appear to the DSO as bilateral transactions. In other words the DSO does not get involved in selecting winners and losers among such parties. However, in accommodating bilateral transactive exchanges the DSO must make sure that that (1) these transactions do not cause disruptive system reliability issues impacting other consumers/prosumers, and (2) to the extent possible use and dispatchable resources at its disposal to accommodate such bilateral transactions before denying or curtailing those transactions that violate distribution system operating limits. The DSO must determine the cost of such dispatch, their proper allocation to transacting parties, and advise the parties to bilateral transactions of the costs involved so that they may revise their bilateral deals accordingly. Such information may be provided to the transacting parties through locational price signals or other means envisioned in the design of the transactive energy market. The distribution system constraints of primary concern to the DSO are flow limits on distribution feeders, voltages, and phase balancing constraints. Without getting into details of distribution system operation, it is best to illustrate this through an example:

> <u>Illustrative Example:</u>
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> Assume a prosumer (Sam) on Phase A with rooftop solar PV strikes a bilateral deal with a neighbor (Peter) on Phase B who is willing to buy electricity from him to charge his electric vehicle. There are other distributed energy resources on these phases that are willing to increase or decrease their consumption at strike prices they have indicated through their bid and offer curves. The system is phase balanced before the bilateral deal between Sam and Peter. The distribution system operator (DSO) operating has the fiduciary responsibility to operate the distribution system reliably at least cost. There is a limit on phase unbalance that the DSO can tolerate within its operating procedures. The DSO realizes that the bilateral deal between Sam

> and Peter will violate the phase unbalance limit. So the DSO dispatched available distributed energy resources on phase A and B to accommodate this bilateral transaction. This results in a re-dispatch cost that must be recovered by the DSO. Since there are other (passive) consumers not engaged in transactive exchanges, it is important to compute and allocate such re-dispatch costs to the culprit transactive parties (Sam and Peter) rather than all consumers/prosumers.

This cost allocation based on cost causation is rather straight forward in this simple example. But, where a large number of bilateral transactive exchanges are involved the determination of the parties causing the need for increased (or reduced) distribution system operating costs as a result of transactive exchanges is not straight forward and requires careful design of transactive energy markets, payments, charges, etc., to ensure an efficient incentive compatible setting.

The best way to address this issue is an incentive-compatible transactive energy market design and corresponding bidding, market-clearing, pricing, compensation and cost allocation rules.
Once properly designed proper software is needed for the DSO to operate the system in a transparent manner with a level playing field for the transactive parties and with no impact on those not engaged in transactive exchanges.

The key considerations in addressing this issue are first the recognition that transactive energy exchanges entail consequences in terms of system reliability, quality of services, and costs (and sometimes benefits) to those prosumers/consumers who do not have interest or do not engage in transactive exchanges. This points out to the need for a Transactive system design that accommodates peer-to-peer transactions, as well as voluntary prosumer supply and demand bids and offers, and passive prosumers/consumers with proper pricing, payment, and cost allocation based on cost and benefit causation.

The most effective method for addressing this issue is to assemble a team composed of market designers, distribution utilities, prosumers, and regulators to draft, discuss, and finalize an incentive compatible transactive energy market design, in addition to a vendor consortium to develop the supporting distribution system operator software and system recognizing various sources of distribution system static and dynamic data, including user interfaces for effective, efficient, non-discriminatory, secure and timely information exchange with the DSO. A testbed should also be constructed to try the transactive energy market and transactive energy system design before full deployment.

What implementation process and safeguards will be necessary to ensure that the market is operated transparently and equitably, without market power abuses?

From April through December 2000, wholesale electricity prices unexpectedly rose by 800% in the newly-deregulated California wholesale power market, accompanied by rolling blackouts, spawning probably the most severe electricity crisis in U.S. history. The cause of this crisis was an artificial supply shortage brought about through market manipulation by Enron and other companies. End-use customers were protected from this spike because of state-imposed caps on retail electricity prices, but as a consequence one of California's largest electric utilities was compelled to file bankruptcy, and another nearly did so.

The root cause of this electricity crisis, however, was poorly-crafted deregulation legislation, passed a few years earlier, which created unanticipated loopholes for the type of market manipulation that Enron and other companies engaged in. It provides a sobering lesson to policymakers throughout the U.S. on the risks of enacting legislation or regulations that fundamentally change the structure of a market as complex and critical as electricity.

New transactive energy systems present the potential for a similarly-sweeping change in electricity market design. It is imperative, therefore, that when and if such systems are being considered, a careful evaluation should be made of the inherent risks associated with these systems. This will entail identifying what entities will be engaged in the transactive energy market, how prices will be determined, and, most importantly, what opportunities exist for exploiting the process. As a starting point, stakeholder input obtained in a systematic and open process would be highly useful in identifying potential concerns.

A possible approach to identifying necessary safeguards might be to "stress test" the system, using some form of effective simulation which includes incentives for participants to find effective means of "gaming" the system for personal advantage. One example of such an approach may be agent-based modeling. This modeling may be combined with simulations of the operation of the electric grid but are not in themselves engineering simulations. These are economic analysis methods, not engineering tools. Other techniques may also be available.

Another potential method for addressing this concern is to learn from those transactive energy experiments and demonstration projects that have already taken place in other states, or in other countries, taking note of what processes and safeguards were implemented to assure that these worked transparently and equitably, and also observing where the systems might have fallen prey to market power abuses and how this came about. Market economists will comprise a particularly useful resource for exploring safeguards, but caution must be exercised to ensure that these are drawn from a pool that does not have a stake or prior viewpoint in the outcome – either positive or negative. For example, it should not consist exclusively of those who are supportive of or advocating the proposed new system.

A transactive energy market would be created by legislative design and further shaped by regulation. Such markets are highly complex and it may be very difficult to get everything right the first time. Such markets need to be carefully and unbiasedly monitored, and the ability to make needed improvements in the market should be part of the process. Any such changes, however, must continue to be made in a clear, transparent, and justifiable manner.