Electric Utility Business and Regulatory Models

California Public Utilities Commission
Policy & Planning Division

Kristin Ralff-Douglas
Principal Author
POLICY AND PLANNING DIVISION

Marzia Zafar
Director
POLICY AND PLANNING DIVISION

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Forward

In September, 2010, Peter Fox-Penner of the Brattle Group gave a presentation at the CPUC based on his book, *Smart Power*, regarding the future impacts of many of the agency's demand reduction energy policies on revenue collection, rates, and the overall financial health of the California investor-owned utilities. Since that time, the topic of utility business models has been broached in many of the CPUC's proceedings. Most recently, it is a topic that affects a number of proceedings that resulted from the passage of AB327[1] which calls for new rate structures, a future Net Energy Metering ("NEM") framework, a new Renewable Portfolio Standards ("RPS") target, and a Distribution Resource Plan. Each of these areas is directly affecting and being affected by the changes that have been taking place in the electric sector. While none of these proceedings directly addresses the topic of the business model of the future, each of them indirectly discusses major components of the model. The CPUC's Policy and Planning Division (PPD) is providing this overview of the issues to support a comprehensive dialogue among the multiple stakeholder groups involved in the CPUC proceedings.

Introduction

The question of the business and regulatory model of the future *utility* is really the question of the model of the future *grid*. What services will be provided? By whom? At what cost? How will providers be compensated and incentivized? How will customers be engaged and incentivized? And what will the role of the utility be in this future grid?

A picture of what the electric grid of the future looks like has begun to form: smarter, more flexible, more integrated, more market-based, and more democratic. Lines are beginning to be blurred in terms of who is providing services and who is consuming them, especially when consumers start morphing into "pro-sumers"— customers who consume as well as produce energy. Whereas the old grid was a one-way communication system and the roles were clear and the lines between them were in bold ink, the new grid is far less rigid and far more integrated.

This new integrated grid and its new communication functionalities challenge the industry to revisit the business and regulatory model of the electric utility that has existed for over 100 years.

There are four main issues that are being discussed among the electric utility industry stakeholders as both challenges and opportunities regarding the application of the current business and regulatory model to the future grid that will be discussed here:

- The cost-of-service model as the traditional utility business model is considered outdated because its fundamental operating principles are the concepts of sales growth and large asset acquisition, both of which contradict current energy conservation policies.

[1] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327

- The once-clear boundaries of the natural monopoly role of the electric utility are blurred because new applications of technology and new financial innovations are leading to more competitive markets and a potential unbundling of utility services.
- As the electric distribution grid moves from a centralized, one-way network towards an open and flexible network, it will open the last area of utility-controlled domain to competitive markets, since generation and transmission are already open to competitive solicitation.
- The financial stability of the investor-owned utilities (IOUs) is being challenged because their diminishing profit potential may harm the utility's attractiveness to investors, thereby weakening their credit rating and increasing their cost of capital and their risk profile.

The main concern of the industry is that the rate of change that the electric utility sector in California is experiencing may be outpacing the cost of service model which underpins the industry. While much of the recent industry discussion has centered on the challenges to the utility income stream, arguably the more important challenge facing the utilities is to its role in the electric grid. The business and regulatory model that has existed for the last 100 years has provided not only a model for revenues and profits, but also a model for a centralized role in the grid. However, each of the issues mentioned above lead to a question larger than just those concerning income and revenue streams – what should the utilities be in the future? What services and value should they provide and to whom? What is the role of the market, and how should the utility interact with the key players in the market? What role will the customer play, and how can customer engagement be optimized? As the electric sector embarks on the challenge toward reaching the 2030 emission reduction goals laid out in Governor Brown's executive order[2], much of the discussion in the industry will continue to revolve around what role the various parties should play in implementing the new policies and regulatory efforts developed to achieve those goals. This question often leads to a discussion of whether greater competition yields greater results or conversely whether strengthening the monopoly status of the utilities will facilitate more expeditious policy outcomes. Others believe it is not a binary choice, but rather a choice that the regulators should determine on a per policy basis rather than an overall electric sector basis.

There are generally three business and regulatory models being proposed by various stakeholders in the industry nationally. In the second half of this paper, we will review the most-discussed options for the utility role being identified by market participants and think tanks around the country. The three run a wide spectrum from a role where the utilities expand their dominant position in the industry, to a role in which they are more actively engaged in facilitating competition and customer choice, and finally to one where they are virtually silent partners in transferring energy from point to point.

[2] Executive Order B-30-15, http://gov.ca.gov/news.php?id=18938

Each of these models represents not only a specific role for the utility, but also for the customers, the regulators, and key players in the market. Each of these models also outlines the compensation models Since the role that the utility actually plays on the grid may have less to do with the direction from the regulatory structure than its direct correlation to what role it is incentivized or paid to play, each of the models also contains a brief discussion of the methods by which the utility would be compensated for its services. There are several options currently being discussed in the industry in addition to or in replacement of the return on equity model imbedded in the current cost of service model, including fee-for-service or performance-based compensation models.

The purpose of this paper is not to advocate for any one model, but rather to describe the models being considered by the industry stakeholders and review their positive and potentially negative impacts.

Section 1 – Disruptive Challenges to the Current Business Model

In August, 2013, *Bloomberg Newsweek* published an article entitled, "Why the U.S. Power Grid's Days are Numbered," in which they attribute the following sentiment to David Crane, Chief Executive Officer of NRG Energy, a power wholesale company: "Regulators set rates; utilities get guaranteed returns; investors get sure-thing dividends. It's a model that hasn't changed much since Thomas Edison invented the light bulb. And it's doomed to obsolescence." In January, 2013, the Edison Electric Institute (EEI), a non-profit trade association of all investor-owned utilities in the U.S. instigated the flurry of dire predictions with their paper entitled, "Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business."[3] In this paper, they predicted a vicious cycle of decline in the utility industry due to declining sales from an increasing number of customers adopting distributed generation (DG). Industry pundits dubbed the phenomenon a "Death Spiral," and echoed and expanded upon the predictions of the EEI report that the electric industry faced a daunting decline. Since then, much of the rhetoric has been significantly tamed, and the thinking has evolved as a result of a number of papers written, conferences held, and even organizations formed to discuss the challenges. In this section we will review the major challenges to the investor-owned utilities (utilities) portrayed by the industry stakeholders.

California's investor-owned utilities do not share all of the disruptive challenges faced by utilities in other parts of the country due the regulatory structure in California and some of the regulatory reforms that have been instituted here, such as decoupling. Nevertheless, there are several issues that do impact them and those are the issues we will focus on here.

It is also important to note that the term "disruptive challenge" is not a pejorative term. It is a term used in business to identify innovations that disrupt the status quo or sense of "business as usual." Many of these technologies and financial innovations are very positive for the industry in

[3] http://www.eei.org/issuesandpolicy/finance/Documents/disruptivechallenges.pdf

general. The intention of outlining them here is to address how they might disrupt the business as usual aspect of the cost of service model.

1. Cost of Service Model Requires Asset Acquisition

The economic and regulatory foundation of the modern electric system is the “cost-of-service model.” For the past 100 years, this model has relied upon two fundamental premises to meet the regulatory goals of safety, reliability, and reasonable rates: sales growth and asset acquisition[4]. This traditional utility business and regulatory model is starting to be questioned because these core tenets have been undergoing an inevitable and profound shift.

The first fundamental premise of the current model is that the primary mechanism for the utility to make a profit is through a rate of return on equity on capital investments. This means that the utility’s primary profit motive is asset acquisition (*i.e.* ownership of generation, transmission and distribution assets including replacement of aging infrastructure), because almost all other activities, such as procurement, are pass-through costs where there are no shareholder earnings, except where specific incentives are provided. In California, utilities no longer own much generation and since FERC order 1000[5] now allows for competitive bidding for transmission, both generation and transmission are now subject to competitive procurement. Therefore, utilities have been experiencing a declining generation asset base for a number of years already, and may see a declining transmission asset base in the future.

The second fundamental premise is that ever-increasing sales would spread the cost of this asset acquisition among a growing pool of customers, keeping prices relatively low per unit of sales (*i.e.*, on a kWh basis). These two fundamental principles worked well for over 100 years, when the system was primarily focused on meeting the growing energy demands of a growing population and the economy of scale provided by the utility provided huge benefits to the entire system. Over the past several years, major shifts have been occurring that affect both premises and are now starting to challenge the model: fixed costs have been rising faster than historical norms[6] (due to a number of factors including replacing and modernizing an aging infrastructure and accommodations for distributed generation) and sales are flattening or declining (due in part to energy efficiency and distributed generation).

These divergent trends challenge the cost of service model because if utilities continue to invest in grid infrastructure upgrades and expansion on behalf of ratepayers, and costs and rates increase too rapidly, customers may increase the pace at which they seek alternative sources of power (such as distributed generation (DG)) to avoid the higher rates caused by the investments in the infrastructure. While most customers do not seek to go “off grid,” they do seek to provide enough of their own power to reduce or eliminate their bills. The loss of this customer revenue will increase pressure to raise the rates for the

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[4] Asset acquisition is defined broadly as being any investment in the grid that is rate-based.

[5] FERC Order 1000 is a Final Rule that reforms the Commission’s electric transmission planning and cost allocation requirements for public utility transmission providers. http://www.ferc.gov/industries/electric/indus-act/trans-plan.asp

[6] *The Electricity Revolution*, Brookings Institute Report, November 8, 2013, by Charles K. Ebinger and John P. Banks; Marc Chupka et al., *Transforming America’s Power Industry: The Investment Challenge 2010-2030*, The Brattle Group (Washington DC: The Edison Foundation, 2008).

remaining customers causing more customers to seek to eliminate their bills. Redesigning rates to lower bills and spread the full cost of the grid more equitably among the customer base has been proposed as a solution by some, but others contend that while it might stall the pace at which customers seek alternate solutions due to higher rates, a new rate structure would not change the fact that the fundamental premise of the model has changed.[7] There is no longer sufficient sales growth to mask rate increases.

Conversely, if utilities become hesitant to invest in transmission and distribution infrastructure to ensure reliable service to retail customers at fair and reasonable rates, because the costs, and hence rates, will potentially rise beyond what the ratepayers can tolerate, it will result in less earnings growth than the shareholders demand and less service than the customers demand.

Both the shareholders and the ratepayers suffer under conditions of underinvestment because it results in lower profits for the shareholders and less service for the customer. Both also suffer under conditions where investments continue at a healthy level because given the challenges there is a higher risk profile for the shareholder and higher costs for the customer.

Further, while the current business model and regulatory fixes such as decoupling both provide assurances that utilities will be allowed to collect sufficient revenues to cover their costs, the future trajectory of declining customer sales due to alternative resources means the utilities' costs of service must be recovered from a shrinking or declining sales base.

Ultimately, a smaller sales base may increase the investment risk profile of the utility because while revenues may not be in jeopardy of eventually being collected, there may be some concern regarding when they will be collected, as any uncollected revenue must be re-allocated in the subsequent rate case. In addition, as the overall sales decrease due to increasingly aggressive statewide policies and goals, such as energy efficiency and solar programs, the percentage of revenues that must be collected by each customer class in successive rate cases may become significantly greater. While many argue that risk is not inherently bad, a higher risk profile may lead to higher costs of capital and may be seen as a deterrent to the traditional low-risk seeking utility investor.

Where the customers and shareholders used to be aligned because both benefitted from asset and infrastructure capital investment-based growth, their interests are now no longer aligned. This misalignment is what is prompting industry stakeholders from many different parts of the industry to call for the consideration of a new business and regulatory model that is more focused on valued-added non-asset based services to the customers rather than pure growth and asset acquisition.

2. Technological and Financial Innovations Challenge the Monopoly Status

The monopoly role of the utility is also changing profoundly because of new applications of technology and new financial innovations, both of which are leading to a more competitive market and eroding the

[7] Rate redesign is discussed at length in an ongoing proceeding currently before the commission and therefore is not covered in this paper.

traditional value of the economies of scale provided by the utilities. This new competition is very different from the restructuring of the electric procurement market in the 1990s which first opened up the market to competition, because the competition is, in many ways, for the customers themselves. California's initial foray into restructuring and competition focused on eliminating the utility monopoly on the generation of electricity by requiring the utilities to divest their generation facilities. Next, retail choice was implemented, allowing customers to choose from a variety of alternative suppliers of electricity other than the incumbent utility. Lastly, this era saw the creation of an Independent System Operator for the transmission grid and the creation of a wholesale market. For the most part, these competitive efforts were focused on utility-scale investments, whereas today, competition from new entrants is increasingly focused on a much smaller scale, such as customer-side distributed generation.

Technology has further challenged the status of the utility as the sole provider of energy. Microgrids, energy storage, distributed generation (DG), and electric vehicles (EVs) are all increasingly available to a greater number of customers. As these technologies have become less expensive, it has allowed customers to produce and store their own power, making them "pro-sumers" not just consumers. These technologies generally do not require the economies of scale that previous technologies required in order to get built. Moreover, new financial innovations allow customers of many different types access to financing options from many different sources in order to acquire these new technologies. Customers no longer need the utility access to cheap capital to finance new technologies.

Technologies associated with the smart grid allow for more services and service providers. Data collection, solar installation, microgrid technologies, and communicating thermostats are only a few of the innovative products and services that vendors are offering directly to customers that the utilities have not historically been able to provide for many reasons including regulatory constraints.

Adding internet capabilities to the grid further changes the relationship of customers to their energy and their energy supply. As a result of these technologies, customers have higher expectations of communications, information and data exchange and service reliability. Many competitors have emerged to meet the growing needs of the customers, some of whom are working through the utilities' customer relationships, some of whom are approaching customers directly.

Paradoxically, the more investments the utilities make in the newer, smarter grid, the less revenue they may collect and the less profit they may ultimately make under a cost of service model because each smarter element provides a new avenue for a new market entrant competing for their customers. Moreover, there is more market and regulatory pressure to utilize the new grid capabilities to foster more robust markets, bringing in more third party providers. The expansion of the distribution grid will only hasten that eventuality because utilities are generally not nimble enough to develop and acquire regulatory approval for new services in time to be competitive. The pace of change is rapidly increasing and the utilities, and the associated regulatory model, are not designed to keep up with that pace.

Under a more competitive paradigm, the electric system could derive many new benefits because competition often drives costs down and innovation up. However, the cost of service model is not currently designed to foster the competition or to incentivize the utilities to embrace the competition.

3. The Distribution Grid Adds Functionality *and* Competition

The CPUC recently instructed the utilities to modernize the electric distribution systems they own to "accommodate two-way flows of energy and energy services…; ….enable customer choice…; and animate opportunities for Distributed Energy Resources (DER)[8] to realize benefits through the provision of grid services."[9] In other words, the utilities were directed to develop a plan to make investments on the distribution grid that will enable and encourage customers and third party providers to engage in a two-way market with the utilities – where the customers are both buying from and selling to the utilities. "An inevitable consequence of these rapidly evolving changes to utility distribution will be the need to add new infrastructure, enhance existing networks and adopt new analytical tools to allow consumers to be active managers of their electricity consumption through the adoption of distributed energy resources (DER); the goal is to create a distribution grid that is "plug-and-play" for DERs."[10] The Assigned Commissioner Ruling (ACR) also asks that the utilities maximize the accessibility for DER, yet keep the budgets reasonable, because those investments in grid modernizing technologies are passed on to the grid users through rates and tariffs.

One indication of where industry leaders think the distribution grid is going is offered by the More Than Smart Group.[11] In the Order Instituting Rulemaking (OIR) initiating the Distribution Resource Planning (DRP) proceeding, the Commission attached a paper entitled, *More Than Smart: A Framework to Make the Distribution Grid More Open, Efficient and Resilient*.[12] The vision outlined in the paper is an open platform that would "involve foundational investments in information, communication and operational systems not seen in existing utility smart grid plans." It argues that the value of DER services to optimize markets and grid operations can only be realized by moving away from a "centralized, linear, closed network towards a node-friendly, open and flexible network."[13,14] The Group recommends expanding the role of DER on both the distribution system and the transmission power system. In fact, it believes "California should expedite DER participation in wholesale markets and resource adequacy, unbundle distribution grid operations services, create a transparent process to monetize DER services, and reduce unnecessary barriers for DER integration." [15]

This new network would be further optimized through a distribution system operator (DSO) "acting as a technology neutral marketplace coordinator and situational awareness and operational information

[8] DER is defined in R.14-08-013 on page 14, using the PUC 769 definition. Distributed energy resources are "distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies."
[9] R.14-08-013, page 3
[10] ibid
[11] More Than Smart started as a collaboration between Caltech's Resnick Institute, the Greentech Leadership Group and the Governor's Office of Planning and Research to organize a set of conferences to discuss how to institute the changes necessary to enable a DER friendly grid.
[12] Link to *More Than Smart* paper: http://greentechleadership.org/programs/smart-2014/
[13] *More Than Smart*, page 4.
[14] A node is defined as a distribution grid interface with customer or merchant DER or microgrid. (ibid, page 12)
[15] *More Than Smart*, page 4.

exchange facilitator." The Group argues that the DSO could have an integrating role with the California Independent System Operator (CAISO) and provide more coordination between the bulk power systems and the distribution systems, which today are operated largely independently. "This integration requires both an expansion of the minimal functions of utility distribution operations and a clear delineation of roles and responsibilities between the CAISO and utility distribution system operators." This vision suggests a role for the utilities as distribution grid operators akin to the role CAISO plays on the transmission level, a role the utilities are not currently playing, nor one that they would be appropriately incentivized to play under the current business model. Currently, the utilities operate the distribution grid for reliability. In this expanded role, the utility/DSO would operate a market, not just a grid. For example, they would be able to value and procure services at certain locations to relieve congestion. This intervention of a market function is possible due to the grid modernization investments that allow the utility to have better visibility into real time operations of the grid.

The More Than Smart Group's vision of the future grid is significantly different than the current distribution grid and challenges the current business model of the utility, from the utilities' role in the operation of the grid, to the services the grid provides and the mechanisms by which the owner of the grid can profit. Currently, the COS model limits revenue collection by the utilities to costs incurred to provide service, as approved by the CPUC; there is no opportunity for the utility to charge a fee for service. Therefore, while a utility is made whole in terms of recovery of its costs through sales to utility customers, there is no profit opportunity or motive. Further, since the profit motive of COS is asset acquisition (*i.e.,* the ROE on assets), the regulatory design itself motivates the utility to demonstrate preference for utility owned and operated assets, such as its own DERs rather than those of the market, or to recommend capital projects, such as infrastructure solutions to reduce congestion rather than focusing on more efficient operation of current assets or resources, or procuring services from third party DERs. It is unreasonable to expect the utilities to act against their own best interest, especially when either way, the needs of the customer are served.

While the ACR states that the DRP proceeding is not about "reinventing the existing utility distribution services model," but rather the "goal of these plans is to begin the process of moving the IOUs towards a more full integration of DERs into their distribution system planning, operations and investment," the ACR is open to future investigation of any changes to business models and utility service platforms. "It is my intent that in 2-3 years, we will move beyond questions like how to quantify and operationalize the locational value of DERs, towards a focus on the relationship between the IOUs, consumers, third party DERs providers and the California Independent System Operator (CAISO)," [16] President Picker says in the ACR.

In their "Reforming the Energy Vision (REV)" proceeding,[17] the New York State Public Service Commission (NYPSC) opted to handle the development of new grid capabilities and a new business

[16] R.14-08-013, page 6
[17] http://www3.dps.ny.gov/W/PSCWeb.nsf/All/26BE8A93967E604785257CC40066B91A?OpenDocument

model simultaneously. "REV aims to reorient both the electric industry and the ratemaking paradigm toward a consumer-centered approach that harnesses technology and markets. Distributed energy resources (DER) will be integrated into the planning and operation of electric distribution systems, to achieve optimal system efficiencies, secure universal, affordable service, and enable the development of a resilient, climate-friendly energy system." [18]

The REV February 26 Order Adopting Regulatory Policy Framework and Implementation Plan [19] outlines the reasons why changing the distribution system platform is no small undertaking and will have major consequences for the electric sector: "The functional center of the REV framework is the distributed system platform provider or DSP." Initially, the IOUs will be the DSP and their role is defined as: "The DSP is an intelligent network platform that will provide safe, reliable and efficient electric services by integrating diverse resources to meet customers' and society's evolving needs. The DSP fosters broad market activity that monetizes system and social values, by enabling active customer and third party engagement that is aligned with the wholesale market and bulk power system." [20]

Both the REV plan and the More Than Smart Group's plan for the distribution grid would significantly change the role of the utilities. The REV decision places the utilities in the role of the DSP/DSO, which is a decision that California has not specifically made. This expanded role of DER and a new market-oriented focus for the distribution grid is at the core of many of the industry led discussions regarding the need to consider a new business model.

4. Disruptive Challenges May Compromise IOUs Financial Stability

Historically, the monopoly status of the utility has provided many financial benefits to the system. Its low-risk investment status provided both access to low-cost capital that kept the costs and therefore the rates down and sufficient capital to invest in very large, costly systems that could provide universal service without concern of the ability to make a profit on each customer or kWh, but rather a return on investment on the system as a whole. Currently, there are many financial functions that the utilities provide that require them to have a strong balance sheet. As discussed earlier in this paper, many of the ambitions for the distribution grid will be quite costly to implement. The ability of the utilities to invest significant capital in the distribution grid is in part a function of their ability to attract investors in order to increase the size of the capital structure.[21] In turn, their ability to attract investors is a function of their ability to provide a profit for shareholders – a profit that is based on the amount of equity invested in a capital project.

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[18] Order Adopting Regulatory Policy Framework and Implementation Plan, page 2 http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b0B599D87-445B-4197-9815-24C27623A6A0%7d
[19] Ibid
[20] Ibid, page 2
[21] Capital structure is a framework of different types of financing including debt and equity.

The investment of equity versus debt capital is a critical decision. As utilities do not earn a return on debt capital, only equity capital, the utilities are more inclined to invest in equity than debt. It is more profitable for the shareholder if the utility invests more equity. However, it is less costly for the ratepayer if the utility invests more debt capital because it usually has a lower interest rate than the rate of return a utility can earn on equity.[22] In order for the utility to attract more investors, it is motivated to utilize equity in capital projects. But, in order to keep rates reasonable, it is encouraged instead to issue more debt. This has been an ongoing debate for years, but in a climate of declining sales, utilities are now concerned about the impact of rate hikes on their customers. Because utilities are likely to recover their reasonable costs, they can carry high debt ratios and still have access to low interest rates and exploit tax advantages. However, their access to low interest rates is also a function of their overall profitability and ability to attract investors. If investors perceive the utility is not making decisions in the best interest of the shareholders, they will invest elsewhere. If investor rating agencies such as Moody's determine that the utility is no longer a good investment, their investment rating will decline and their cost of capital will increase because the interest rate on debt will increase which in turn will impact the cost of service and ultimately rates.

In addition to securing low interest rates, a healthy utility balance sheet also provides security for long-term contracts signed with independent power producers (IPP). An increasing share of the generation portfolio is acquired through power purchase agreements (PPA) with IPPs. These contracts actually have the potential to add greater risk to the balance sheets than utility-owned generation (UOG) because many of the PPAs currently count as a liability on the balance sheet. However, since the PPA is a pass-through cost, there is no return on that contract obligation. Most utility scale projects such as large solar plants require that the IOUs sign a long-term (usually 20-year) PPA with the generators in order to get financing to build the plants. Since the utilities were required to sell off a significant portion of their generation portfolio in the late 1990's, the vast majority of the utilities' generation portfolio is non-UOG, hence a larger and growing portion of their balance sheets are filled with pass through, non-income earning projects. Another risk to utility investors is that the utilities now have much larger financial obligations to outside power producers without operational control over the assets. In fact many of the contracts may not have specific generating assets behind the contract which increases the risk of default. The influx of DER projects that are expected as a result of investments in the distribution grid is also likely to pose similar challenges. They are likely to require the same stability of long-term contracts to lower their risk and obtain project financing, and will be lacking specific assets behind those contracts. These risks are exacerbated by the growth in DER itself, which may operate under no contract terms at all with the utility, yet the utility is responsible for maintaining the integrity and the reliability of the grid.

It should be noted that a PPA can also be a good hedge against financial risk for the utilities. In a recent paper, *Clean Energy Investments and Incentives: Choices for Investors, Utilities and Regulators*, Ron

[22] Utility investment risk is low because they are likely to recover costs. As it is considered a lower risk than other private sector investments, it is also given a lower rate of return on equity.

Lehr[23] points out: “It is also a legitimate goal of regulation that consumers should gain the advantages of new technology, diversity of ownership, specialized knowledge, and new business approaches, and the benefits of risk mitigation that are available when a utility enters into a well-structured power purchase agreement with an independent generation supplier.” [24]

Lehr suggests that another key financial consideration in building or buying assets is the connection between the provider of the investment capital and the innovation level of the investment. Utilities have traditionally made low-risk long-term investments in transmission and generation that have afforded them very low cost capital and stable returns. However, there is significantly more venture capital available to fund more innovative energy technologies especially on the distribution grid.[25] By contracting these services and technologies from the market rather than owning them, the utilities may not only hedge the risk to ratepayers and shareholders, but might bring in more venture capital. The recent REV decision similarly points out that while New York’s current business model puts all the risk on the ratepayer, their new model will disperse some of that risk onto third party providers and their investors. Of course, it will also disperse the financial benefits as well.

Lehr also notes that a healthy utility balance sheet is necessary for public safety: “The public interest requires regulators to achieve a balance in which financially healthy utilities have adequate invested equity both to support ongoing operations and to provide an equity cushion against which debt can be raised to address extraordinary needs, such as rebuilding after natural disasters.[26]”

Finally, a healthy utility balance sheet is also necessary for the maintenance of a good credit rating which is the key to capital costs and availability for the IOUs. As of March 2015, Fitch rated SCE as A-, SDG&E as AA-, and PG&E as BBB+.[27] Utilities are rated based on their perceived ability to make a return on investment. Fifty percent of their rating is determined by their business plan and debt levels, and the other half of their rating is determined by the regulatory structure and environment in which they exist. Conversely, most private sector companies are judged with respect to their competition. If the regulatory compact that stabilizes returns is challenged, the method for rating utilities is likely to change and they too will be rated based on their ability to compete for customers.

It is clear that whatever the business model of the future is, the role of the utility will need to be buttressed by a healthy financial balance sheet.

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[23] Ron Lehr formerly served as Chair of the Colorado Public Utilities Commission. He was a principal author on America’s Power Plan. http://americaspowerplan.com/

[24] *Clean Energy Investments and Incentives: Choices for Investors, Utilities and Regulators*, by Ron Lehr, October 2014, page 4

[25] *Energy Firms Aided by U.S. Find Backers*, New York Times, Matthew L. Wald, (with quotes from the Brattle Group.)

[26] *Clean Energy Investments and Incentives: Choices for Investors, Utilities and Regulators*, by Ron Lehr, October 2014, page 4

[27] Moody’s press release, November 6, 2014

Hyperbolic "Death Spirals" aside, there are clearly challenges to the business and regulatory model that will need to be confronted. These challenges are a direct result of the success of many of the state's efforts to promote energy efficiency, distributed solar, demand response and other innovative, environmentally-focused programs, as well as efforts to deploy more competitive tools. As the state begins to develop programs and policies towards achieving the 2030 and 2050 climate goals and the efforts to increase grid capabilities become operational, the challenges to the existing business model will likely be even greater.

A press release from Moody's Investor Services in November of 2014, almost two years following the EEI report, stated that action by utilities, state lawmakers and regulators to refine utility cost-recovery models to stay ahead of a potential industry transformation involving widespread adoption of DG lessens the threat of disruption. Moody's reiterated that "because the electric grid is a critical piece of infrastructure that is a vehicle for policymakers to implement their energy policies…it will become even more important as the platform for the more complex flows of power and information in the utility of the future."[28] Their relatively high ratings for California investor-owned utilities are based on the confidence that the regulators and industry executives will address these challenges.

Section 2 - Options for the Business Model of the Utility of the Future

The challenges outlined in Section 1 highlight that the investor-owned utilities are facing a number of significant countervailing forces. Taken in aggregate they underscore that one of the largest challenges is understanding their very role in the grid of the future. The historic view of the utility as a natural monopoly wasn't tested until recently, because in the past it was clear that the scale of the effort that needed to be undertaken to supply every customer with electricity required a monopolistic enterprise. However, while the scale of the current grid expansion efforts may not necessarily be any less monumental than past efforts, the localized implementation opportunities do not necessarily require a centralized system or source of funding. In addition, many customers want to participate more fully in the grid, and to achieve the state's increased greenhouse gas emission reduction goals most will need to participate more fully. This new reality provides for new opportunities for market participants and customers that have not been available before. The role of the utility of the future will need to be defined by how the utility can best help foster those customer and market interactions. The current business model, for myriad reasons, may not be best suited for that task. In this section, we will review three models that industry stakeholders have put forward that they contend may be better equipped to navigate the new grid and provide ample opportunity and reward for the customer, the market participants and the grid.

[28] http://www.platts.com/latest-news/electric-power/washington/electric-utility-death-spiral-in-us-is-premature-21516803

Business and Regulatory Models of the Future Utility

Over the last several years, three models main models have been discussed within the industry. There are many variations on these models, and while there is not yet consistent meaning or vocabulary around them, there are some basic understandings for each that allow for comparison and analysis.

The analysis provided in this paper is not intended to provide a recommendation, but is intended to identify the likely implications of adopting any of these models.

The three models range from a high level of utility participation and interaction to a minimal role in the grid and all of its services. The level of participation of market participants in each is converse to that of the utilities. As was observed in the PPD paper, *Customers As Grid Participants,*[29] the role of the customer on the grid has profoundly changed, therefore the assumption that the customer is a highly engaged participant on the grid is the same in all three models. However, from whom the customer receives services and to whom the customer sells services is different in each model.

In the CPUC's current DRP proceeding, it requested that all three utilities develop detailed plans for building a more robust distribution grid. Because this plan is already under development, all three of the business models of the future grid assume that a robust distribution grid will be part of the future of the grid and that some entity will be in charge of operating that grid.

Each of the models can be considered to be both business and regulatory models in that they define the boundaries of operation that would be imposed via the regulatory authority of the CPUC. Since none of the models being discussed by stakeholders propose a completely unregulated utility, and the revenues of the utilities are still therefore subject to regulatory approval, all of these models can be considered both regulatory and business models.

1. Model 1: The Utility Expands Its Dominance in the Sector

The first model represents the high end of the spectrum of utility involvement in the grid. In this proposed model, the utility would expand its current dominant role in the grid by expanding the services it offers as well as its revenues streams in order to bolster its balance sheets and continue to attract investors.

Under this expanded role model the utilities would retain all responsibilities they currently hold for safety, reliability, and affordability. They would also continue to be the provider of last resort, and maintain responsibility for achieving energy efficiency goals, storage goals, and the renewable procurement standard, among other regulatory mandates. The mechanisms by which these programs are implemented may change over time. For example, the energy efficiency programs and services might be run through the utilities or through a third party, or alternatively the utilities might rely more heavily on the market to provide needed services, but ultimately in this model the utilities retain both the regulatory obligation and financial obligation.

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[29] http://www.cpuc.ca.gov/NR/rdonlyres/A0A816A2-9F1C-4F34-90DB-C23551F09738/0/PPDCustomerRoleMay15th.pdf

This model also assumes that the utilities would operate and manage the distribution grid. There is wide latitude within which the rules can be designed, but a broad vision would include the utilities upgrading and maintaining the distribution grid, directing the investments to locations that have the greatest value and need, procuring supply and demand resources, and contracting with the various service providers on the distribution grid. In addition, the utility planning process would likely continue to be a long-term portfolio-wide process that would include assessing the future load demand and recommending the balance of utility-scale versus distributed resources to meet those needs.

Cost of Service could still be the primary rate setting model. Various performance-based incentive payments for meeting program goals could be incorporated, and the utilities could still benefit from operational efficiencies. However, in order for a utility to be financially stable and to continue to attract investors so that it can fund the new grid, proponents of this model argue that it would need to rely heavily on providing new forms of income and profit centers to the utility and would likely include opportunities for the utilities to reach behind the meter to provide services to customers. Proponents assert that if utilities were able to provide or procure new products and services that were either rate-based or fee-for-service, they would be indifferent to the customer being highly energy efficient, because the income from the rate-based services would offset the lost income to the utilities from the reduced sales. This would make them indifferent to whether a customer was a consumer or a pro-sumer because either way the utility is provided an opportunity to earn a return from providing customers with the products and services that the customers chose, whether it is energy efficiency or distributed energy or both.

It is also important to note that this model proposes that services be offered by the utilities directly, not through their affiliates. While this model does not prohibit their affiliates from providing services, the objective is to provide the utilities, not their parent companies, with additional revenue streams. Sales through affiliates will not resolve most of the challenges to the COS model such as delayed revenue collection or increasing customer bills, and therefore, do not ultimately provide a solution to many of the challenges presented in the COS model.

Under this expanded role model, utilities could also be allowed to own distributed and utility scale generation and storage, so that new renewable and storage mandates would not further degrade their income potential and further weaken utility balance sheets. It is possible that the smart grid upgrades and distribution grid expansion will provide sufficient asset acquisition and opportunities for a profit on shareholder investments for the foreseeable future. The size of the investment may even be on par with past spending on transmission and generation. If it is enough to maintain a healthy balance sheet, then the utilities would be in a strong position to attract new investors and fund the new investments. Utilities in California are currently allowed to build UOG under certain circumstances and when approved by the regulators. In an expanded role model, proponents assume that the utilities would be granted this option more often. In addition, utilities are currently prevented from providing services behind the meter or from charging a fee for service; any changes to these rule would require regulatory and perhaps legislative intervention.

Whether the utilities expand or contract their role, it remains likely that bills and, potentially, rates will rise. How high is both a function of the cost of system upgrades and how many people it can be divided amongst. A shrinking ratepayer base means fewer people bear a larger percentage of the costs, which increases their rates. Therefore, under this model it would be important that the rate structure be designed to ensure equitable distribution of costs and benefits. This model does not discourage third party providers or customers from becoming pro-sumers, nor does it discourage a potential for fee-for-service payment structure, where anyone providing services to the grid receive compensation for that service. Like the utilities, the pro-sumers, aggregators and service providers on the grid would also be collecting fees for their services. This model does not preclude an active market or dynamic pricing, but it does assume that the market would be primarily driven by the utility and would therefore be responding to the price signals and resource signals sent by the utility. For example, if a utility issued a request for a proposal (RFP) for DER services, the market would respond with competing bids based on the specific parameters outlined by the utility.

Proponents of this expanded role model argue there are three main benefits: one is that the utilities continue to be the obligated entities in terms of delivering energy efficiency, utility scale renewables, storage mandates, emission reduction mandates, reasonable rates, *etc*. The regulatory authority of the CPUC over the utilities would not be diminished under this scenario, nor would the opportunity to have utilities invest in areas where there is a societal benefit but where a private company might not be able to earn an immediate return on investment and yet where an IOU would (*e.g.* the installation of smart meters). The CPUC would retain its authority for setting rates, fees and return on investment rates for the utilities, and for requiring various safety and reliability standards. This model would retain the stability of a regulated monopoly.

Opponents point out that there are also challenges to this model. One challenge would be a rate design that is considered equitable for all users on the grid, whether the user is a consumer or pro-sumer. The current rate redesign proceeding is wrestling with equitable distribution of costs through cost causation and cost allocation principles. Proponents of this model point out that with more services and distributed assets allowed to be rate-based, the customer base would remain large enough to ensure that costs are not borne disproportionately by any one group. However, concerns raised by opponents of this model contend that while a more equitable distribution of costs might lead to better rate design, costs are still increasing, which will drive higher rates. They argue that decreasing sales will still mean a smaller base to which the costs can be spread, and without a more competitive market, customers are trapped in the high rate services.

Another downside of this model is that it essentially sanctions the utility as the largest service provider, protecting its access to the customer base and its control over the distribution grid. Opponents argue this control may dampen market innovation and limit customer choice. Opponents also argue that the only way to promote innovation in this model is to allow for an increased level of utility risk. Under cost of service models, risk undertaken by the utility is usually a cost borne by the rate-payers since the investments are rate-based. Conversely, proponents contend that the utilities would not necessarily be incorporating more risk to promote innovation because the utilities would still have to contract out many services, these contracts might lead to a robust development of ideas, services, new technologies and financial tools that benefit from the lower cost of customer acquisition because they are marketed through the utilities. The lower cost of acquisition can make up for the higher risk of innovation. However, opponents counter that while those few companies with contracts would benefit enormously from the reduced risk of having to approach customers independently, there would be substantially more companies that would not get contracts. This lack of opportunity to get market share may lead to a fracturing of the grid, where products and services start to emerge outside of the grid, for example, via the internet, and the costs and benefits of those options are not really captured by the system or equitably distributed or priced competitively.

Further, a bifurcated market could present a planning challenge for the utilities. In that case, the utility would be pursuing its planning and procurement efforts to accommodate a customer load over which they would have decreasing knowledge and control. In addition, opponents argue that this model would not fundamentally change the asset driven profit model of the utilities. It may diversify their income opportunities by allowing them to offer and charge for services, but the majority of their income would still come from capital investments in assets.

Finally, to many this model does not offer an end solution, but an interim plan to overcome some of the financial concerns facing the utilities and limit rate increases on some customer classes. Opponents argue that implementing this expanded role and increasing the role of the utilities could be harder to unwind if it proves to be inadequate. However, to others, this model is a paradigm shift that finally moves utilities into the business of providing value and services rather than just selling commodities and acquiring assets.

2. Model 2: The Utility Focuses on Facilitating Competition and Customer Choice

The principle vision of this model is the utility as the owner and operator of the distribution grid where their primary responsibility is to create an interoperable platform off of which many market participants could engage. In his book *Smart Power: Climate Change, the Smart Grid, and the Future of Electric Utilities,*[30] Dr. Peter Fox-Penner describes the utilities' mission in a model such as this as the following: "to deliver electricity with superb reliability from a wide variety of sources, from upstream plants to in-home solar cells, all at prices set by regulator-approved market mechanisms."[31]

The key difference between this model and the expanded role in Model 1 is the nature of the role of the utilities in overseeing access to the distribution grid. In Model 1, the utilities would *manage* the grid operations including overseeing who would be able to provide services on that grid. Conversely, in Model 2, they would be responsible to *facilitate* competition on the grid. This is a key difference. If the utilities are charged with *managing* the grid in Model 1, they are responsible for who gets access to the grid and what services are provided to whom. In other words, the utility would be responsible for acting as a gatekeeper. This control would give utilities the flexibility to contract with specific DER providers for

[30] Peter Fox-Penner, 2010
[31] *Smart Power*, page 175

services to utility customers, or issue a competitive bid process, or provide the services directly. *Facilitating* the grid in model 2, on the other hand, suggests that the utilities are responsible for creating an interoperable platform and ensuring that there is an equal playing field for anyone who wants to offer services on the grid to customers. Either way, as the distribution grid operators, the utilities would be in charge of ensuring that electricity is provided where it is needed, reliably and safely. They would also be in charge of maintaining and operating the grid, and developing investment and upgrade plans. In this Model 2, the utilities could also provide DER services, but most likely they would only be doing so under limited conditions where the market is unable to respond. However, pricing structures could be vastly different under the two model scenarios. If a grid is managed by the utilities, then the regulatory agencies retain control over the rate setting, but if the grid is only facilitated by the utilities, then the service providers would very likely get to set their own prices under a more competitive market structure.

The New York REV decision establishes a distribution grid operator model with the utilities as the operators. The REV model parallels this Model 2 in many respects. However, in the transition phase while regulators work to "animate the market," the utilities will operate more as managers of the grid than facilitators, with functions of planning and procuring similar to the current processes. Nevertheless, it appears to be the intention of the NY PSC to move towards a greater market-based competitive system.[32]

Proponents of this Model 2 assert that one major advantage is that it provides many opportunities for utilities to earn revenue. There is no one income model because it could be a combination of cost of service (for the distribution grid), fee based (for any additional services that are distribution grid related), and performance based (with incentives for achieving certain operating or customer service goals). They argue that because the model is predicated on stimulating a market for DERs and other customer services, the financial incentive for the utilities could be structured so that they are aligned to bring more DERs onto the grid by a multitude of market participants.

Proponents also note that in Model 2, the relationship with the customer would no longer solely belong to the utilities. This is a major difference with Model 1, where most of the products and services are offered to the customer by the utility, even when that service is actually being provided by another vendor. Under a Model 2 scenario, where the utility is facilitating competition and customer choice, the utility might aggregate customers' billing and manage and operate the meters, so that the customers would receive one bill for all services from a variety of different vendors to help customers manage more than one relationship.

Data is another area where access and relationships could expand to the benefit of the customers and the third party providers of services. Currently, the utilities own and manage the meters. While usage data is considered the property of the home owner, it is accessible to the utility and its vendors. Access

[32] Order Adopting Regulatory Policy Framework and Implementation Plan, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b0B599D87-445B-4197-9815-24C27623A6A0%7d

to that data for market participants would continue to have to be authorized by individuals or in its aggregate form as directed by recent Commission decisions.[33] However, with more competition there are likely to be more tools to provide access to data, as well as more willingness for customers to share their data with potential service providers.

For its proponents, this model has many benefits. Many of those who are convinced that a more open market would provide for more innovation and customer choice support this model because it opens up many heretofore closed markets. The model allows competition and innovation and private capital.

Its opponents point out that the challenge with this model is to design a market that meets customer needs without discriminating against customers who choose not to participate, or creating unfair benefits for those who do participate. Another challenge for the market would be the cost of customer acquisition. Customers are not a homogenous group. While some definitely want provider choice for electricity and services, and what electricity services they buy, not all customers want a change. In addition, customers are motivated differently: cost savings, energy independence, "cool" technologies or simply "keeping up with the Jones'." In this model, the utility has to maintain reliability and access to electricity for all customers regardless of the options for all customers whether the customers select them or not.

While this model does not necessarily require direct access or retail competition, it certainly does not preclude it. Therefore, opponents of this model also argue that the utility could be saddled with all the uneconomic areas of service, while the unregulated third party entity is able to "cream-skim" or "cherry pick" customers. However, the model allows the utility to make a return on equity from infrastructure investments, as well as profit from fees for services and even earn performance incentives for implementing various regulatory policy objectives. Therefore, it would be financially neutral regarding the provision of services to its customers, either through direct access or not, and "cherry picking" would not be seen as negative to the utility.

One significant challenge in the existing cost of service model is the number of pass-through costs that the utility underwrites and gets reimbursed for, but does not profit from. Under this model, proponents suggest that there would be a presumption that all services using the grid, whether they were energy or ancillary, would be paying for the use of the grid via fee for service or through some tariff. This construct would also have the impact of making the utility financially neutral to who provided what services.

There are also procurement challenges: the grid will accommodate whatever electricity is generated. Recognizing the differing needs of the grid and providing appropriate prices for those services will be very important to ensuring that a variety of resources are utilized.

Current long-term procurement planning proceedings are very detailed and centralized, but in a market-based structure, procurement is based on price not planning. A price-based approach may work well under many conditions, but it invites the discussion of the advantages of procurement through

[33] D.11-07-056, Decision adopting privacy rules and policies on customer access to data.

regulated mandates versus un-regulated markets. California has a history of relying on regulated mandates for renewables, storage, and other preferred resources. It also has a history of procuring utility-scale resources which can be planned for in a methodical way. DER markets will be less predictable and highly localized, and therefore less methodical.

Finally, there are some functions that are either very slow to provide a return on investment to its private investors or may never provide a direct return on investment, but provide benefit to the system. These are areas where utilities have been able to use their economy of scale for the benefit of all customers. While proponents of a more open market suggest that the market has many advantages, they also state that the choice of business models need not be a binary one. In other words, in those areas where competition can flourish, it should be allowed to, and where it can't the utility ought to utilize the benefits of its economy of scale. One challenge for this business model will be identifying where to draw the line for the services that the utilities provide versus those the market provides. Another challenge will be on the regulators to ensure that rules are put in place to safeguard robust competition.

3. Model 3: Utility as Owner of Poles & Wires

This model represents the most limited role of the utilities and the greatest reliance on market participants and customers. There are two poles and wires models, one that is currently operating in Texas and the other being proposed by former FERC Chair Jon Wellinghoff.

The Texas market is largely deregulated and served by a several layers of providers including: the regulated distribution utility companies which own, operate and invest in their poles and wires infrastructure; the retail providers who sell energy services directly to the customers; and the independent generators who sell power to the retail providers based on load identified by ERCOT,[34] which acts as transmission grid operator (*i.e.* the independent System Operator, ISO). The regulated utilities run the distribution grid. Under this model, utilities cannot offer DER services on the market. While this should make the utilities indifferent to consumers and prosumers, it does not make them indifferent to all DER services. In fact, there is an interesting case developing in Texas, where Oncor, a regulated distribution utility, is trying to purchase $5.2 billion worth of batteries to improve the service of its distribution grid. Oncor is being opposed by its sister companies, a generator and retail electricity service provider, because they believe that battery storage is considered generation, not grid infrastructure technology and therefore should be left to the competitive markets to procure. Oncor disagrees, and based on a recent study from the Brattle Group[35], argues that over half of the benefits of grid-scale battery benefits can't be monetized by merchant power providers under the current

[34] Electric Reliability Council of Texas is the independent system operator for the region, it schedules power on an electric grid that connects more than 43,000 miles of transmission lines and 550 generation units. ERCOT also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for 7 million premises in competitive choice areas.

[35] http://www.brattle.com/system/news/pdfs/000/000/749/original/The_Value_of_Distributed_Electricity_Storage_in_Texas.pdf?1415631708

regulations in Texas. This case demonstrates that the utility is not indifferent to all DER services under this model.

Former FERC Chair Jon Wellinghoff recently expressed support for another poles and wires model which would allow utilities to be DER providers. Utilities would own but not operate the grid. That task would be undertaken by an independent distribution system operator (IDSO) akin to the Regional Transmission Organizations (RTO)/Independent System Operators (ISO) on the transmission grid.[36] The utilities on the distribution grid would maintain and invest in the assets they own and derive return on investment income from their capital investments, but they would not control the moment-to-moment operations of the grid, as that would be done by the neutral third party IDSO. Nor would they do the planning for grid investments, as that too would be done by the IDSO.

Under his proposal, utilities could own DERs because the utilities would not have the benefit of market power. In fact, in a recent interview with the Utility Dive blog, he predicted that “an IDSO model would enhance DER investments from both utilities and third party vendors by providing a neutral grid vendor.”[37] He added that states with retail competition like Texas have the greatest opportunity to transform their distribution grid operations. Under this model, Oncor would not have the authority to decide that batteries would enhance their distribution grid services. That decision-making capability would lie with the IDSO. However, if the IDSO wanted to put batteries on the grid (and the batteries were determined to be a DER generation service not a grid operations enhancement service) then Oncor would have to compete with other DER providers for the contract.

One challenge to any variation in this model is technology. In a recent Utility Dive article, the author noted that “effective distribution modeling and control tools such as software to help either utilities or IDSOs better plan for DER investments and allow disparate devices on the grid to act as a unified whole, doesn’t exist yet.”[38] This software is essential for valuing a diverse set of DER grid investments, which they point out “no one has figured out yet, because their costs and benefits can vary so widely based on location, weather and countless other factors.”

In any version of a poles and wires model, the market is the main driver of the system. In Models 1 & 2, the utilities have some responsibility for planning and procurement, which can take into account non-economic issues such as preference for renewables. Conversely, under this model, the preference would need to be priced into the offer in order to be considered. Under this model, the electric market would appear much more like the de-regulated telecommunications market or the natural gas market than the electric markets of today.

[36] FERC Order No. 888 defined the fundamental purpose of an ISO to “…operate the transmission systems of public utilities in a manner that is independent of any business interest in sales or purchases of electric power by those utilities.”
[37] article http://www.utilitydive.com/news/who-should-operate-the-distribution-grid/376950/
[38] ibid

Under the Texas version of the poles and wires model, the distribution utility relies mostly on the income from regulated rate of return on its capital investments. However, as is the case in Models 1 & 2, the compensation model for a poles and wires company could be a combination of cost of service return on equity, fee for service, and performance based revenue or bonuses. One benefit to Wellinghoff's version of the IDSO model is that it maintains the utilities current income stream by providing a return on equity from their capital assets, but it also provides for new income streams from their successful DER projects. It also has the benefit of significantly reduced operational and administrative costs.

Proponents of poles and wires models in general suggest that either would provide all the benefits of a competitive market. Opponents point out that the market dominated electric system may not be able to deliver all of the environmental benefits required by current policies and law – although proponents suggest is it an issue of market design. Unlike in Model 2 where there might be some opportunities for a co-existence of market dominated and utility dominated areas, because the utility is still taking an active role in the delivery of energy on the grid (including procurement if necessary), this model is unlikely to be able to support the two efficiently because the functions of the utility are more isolated.

Clearly each of these business and regulatory models offer very different options for the roles of the utility, the regulator, the market participants and the customers. However, while each one provides an opportunity for expanded revenue streams, none move entirely away from the cost of service model – *i.e.*, paying the utility for its service primarily by providing a return on investment on assets. As a result, none of these models move the utilities away from asset acquisition as their major income stream, and therefore their primary goal.

Lawrence Berkeley National Lab has recently issued a draft paper[39] in which they outline several incremental changes to the utility revenue model to deal with lost revenues from DERs. As the LBNL paper points out, however, while many of the changes may eliminate the utility opposition to DERs, most of these changes are not sufficient for the utilities to be indifferent to DERs, much less encourage them. Moreover, many of the ratemaking alternatives examined in the paper are already being used in California, and while decoupling and energy efficiency performance bonus payments have been successful, they have not been sufficient to overcome the challenges to the current business model.

The LBNL model results suggest that a newly clarified role for the utilities must be aligned with a newly designed compensation model. While Model 3 introduces a market-driven model, the basis for the compensation of the utility is still on the cost of service model. Model 1 might be an opportunity to impose a performance-based rate making system, where the utility is paid based on its achievement of objective goals such as kWh sold to subjective goals like customer satisfaction. Model 2 might be an appropriate place to unbundle costs and pay utilities and all service providers on the grid on a per transaction basis. A business model can only be successful if the role of the utility is aligned with its compensation and the rates to customers are just and reasonable. It is equally important that the

[39] *A Framework for Organizing Current and Future Electric Utility Regulatory and Business Models, Andy Satchwell, et all.*

service providers and customers are also fairly compensated for their roles in the system. DER providers must have a clear way to make a profit, or they will not participate on the system. Customers need a clear investment signal to participate as well. All of these roles and financial incentives must be correctly aligned in order to create an efficient system that sends the correct price signals.

The New York REV process has recognized the same alignment problem. In the February 26 REV decision, the NY PSC outlined a new business model for the utilities which is very different to the role they currently play. Yet, the NY PSC highlighted that it has not yet determined how the utilities will earn a return under this new model. As part of the next phase of their proceeding, they will investigate how to structure a compensation model that is based on adding value for customers and for DER providers, rather than just building infrastructure. Specifically, the NY PSC noted that "Utility earnings should depend more on creating value for customers and achieving policy objectives. Rather than simply building infrastructure, utilities could find earning opportunities in enhanced performance and in transactional revenues."[40] Further pushing the utilities income stream away from infrastructure development to the provision of services, the NY PSC stated that "Under REV, utilities will respond to disruptive trends by adding value to various activities in the evolved power economy, with the concomitant opportunity to earn revenues from new service offerings and the ability to raise capital on reasonable terms."[41] NY PSC will issue a staff report in June on how these ideas might work.

Conclusion

Since the EEI paper, *Disruptive Challenges*, was released over two years ago, the industry has devoted a significant amount of time and energy contemplating the future of the electric sector. Three models have been widely discussed amongst the electric utility industry as options for a future business model: one that expands the utilities' monopoly role, a second that expands the role of a robust market facilitated by the utilities and a third where the regulated utilities own the poles and wires and the markets do the rest. Each of the three models outlines a very different role for the utility in terms of its responsibilities and activities on the electric grid. They each also challenge the market and the customers to take on different roles as well.

The last business and regulatory model worked for over 100 years because the situation under which it operated did not change substantively during that time. One of the big challenges for choosing a model for the future is that the rate of change has increased exponentially. Choosing the model for the future may well mean choosing not only one that can best meet our current goals and grid configuration, but one that is flexible enough to meet the future goals and grid configurations – whatever they might be.

[40] Ibid, page 27
[41] Ibid, page 29

As mentioned in the Forward of this paper, there are many proceedings underway at the CPUC that are taking up the issue of the business model of the utility of the future in some way or another. As they proceed, there are several questions that could be considered to help chart the future path:

How much do the regulators want to rely on regulated mandates versus competitive markets?

Does a natural monopoly paradigm still exist? If not, are there still benefits to a monopoly-based system? Can a monopoly paradigm still be successful if the traditional definition no longer applies?

What benefits does competition offer? What are the drawbacks or unintended consequences of competitive markets? How can they be mitigated? Can they be applied in some parts of the sector and not in others?

What does the compensation system or model look like that promotes the behavior desired from each of the participants in the system: the utilities, the customers and the market players? What is the financial motivation for each segment to act according to its preferred role?

Underscoring all of these questions is the fundamental question: How is the customer best served? What kind of system provides safe, reliable, affordable electricity, but also allows for customer choice and meets our State's environmental goals?

None of the evidence suggests an imminent demise of the system in California, but it does suggest that there are challenges and opportunities worth exploring in depth. Addressing these questions and the many more that they lead to will provide answers that will help define the utility of the future in California.