



# Smart Grid Issues in State Law and Regulation

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The information provided herein is intended to provide an overview of certain smart grid issues in federal and state regulation. It is not intended to provide a complete summary or a complete legal analysis of the federal and/or state statutes, regulations or policies discussed. Note that the legal research is current through April 12, 2010.

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To pave the way for Perfect Power and system transformation as a whole, the Initiative is advocating for new policies that reflect a set of guiding principles — the electricity consumer's bill of rights. For more information on the Electricity Consumer Principles, the policy framework or the Perfect Power System, visit [www.galvinpower.org](http://www.galvinpower.org). Here you will find an array of information on every dimension of the intelligent grid transformation and the Initiative's goal of perfect electricity service for every consumer.



## TABLE OF CONTENTS

|   |          |
|---|----------|
| <b>Summary</b> .....  | <b>3</b> |
| <b>Recommendations</b> .....  | <b>5</b> |
| 1. Historical Barriers and Enablers to Modern High-Performance Smart Grid Deployment .....  | 7        |
| 2. Overview of Federal Legal Changes to the Bulk Wholesale Markets Since the Passage of the Energy Policy Act of 1992 (EPAct) ..... | 16       |
| 3. Policy Context and Recommendations .....   | 20       |
| 4. State Analysis: California .....   | 32       |
| 5. State Analysis: Colorado .....   | 37       |
| 6. State Analysis: Connecticut .....  | 39       |
| 7. State Analysis: Florida .....  | 41       |
| 8. State Analysis: Illinois .....   | 44       |
| 9. State Analysis: Massachusetts .....  | 48       |
| 10. State Analysis: New Mexico .....  | 50       |
| 11. State Analysis: New York .....  | 54       |
| 12. State Analysis: Ohio .....  | 59       |
| 13. State Analysis: Pennsylvania .....  | 62       |
| 14. State Analysis: Texas .....   | 66       |
| 15. Glossary .....  | 69       |

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## Summary

The power sector in the U.S. has been slowly evolving from a series of vertically integrated monopolies providing electric service to discreet geographic service territories, and then to a regionally interconnected, increasingly competitive marketplace. While the transition has been different from region to region, the general trend in the bulk power wholesale market has been one of progress. The changes in the past 20 years have been particularly dramatic. Under prodding by Federal authorities, we have witnessed the emergence of regional transmission organizations (RTOs), sophisticated transmission pricing, the independent power sector, restructured electric utilities, trading in electricity futures and transmission rights, real-time and day-ahead energy markets, and industry unbundling.

However, the situation at the retail level, where state regulation reigns supreme, has been less clear. While approximately half of state retail markets have not been opened to competition, much of the changes realized in retail markets were not as deep as the changes in wholesale markets. Rates were formulated on an average cost basis. Blended, rather than real-time prices, offered limited opportunity for effective demand-side response.

This pricing failed to pass on to end-users the sophisticated price signals emanating from the increasingly sophisticated wholesale market. In effect, the price signals for a more efficient power sector were being deflected before they could meaningfully influence demand itself, the most effective influence on overall efficiency. In short, states fell into two broad categories: one characterized by preservation of the monopoly, and a second that featured the somewhat superficial enabling of competition without fully empowering consumers to make the choices that are generally associated with competitive markets.

There are a variety of reasons for this disconnect between the wholesale and retail markets. An egregious example, of course, was the very conscious decision by California policymakers to legally preclude the passing of wholesale market prices on to end-users. This was a misguided measure that contributed significantly to the crisis that occurred. In most places, however, the disconnect was less a conscious decision than it was the result of other factors. The factors included political difficulties in further reforming markets, the legal residue of the monopoly model, and, not inconsequentially, the lack of a technological infrastructure to support full-market reformation.

The emergence of smart grid technology can enable us to reform electricity markets and create more efficient and allow cleaner use of electricity. This technology promises to provide customers better and more timely information in order to influence more efficient behavior. Digital automation can fundamentally increase the controllability, functionality and resilience of the electric system. High power quality microgrids can potentially operate as innovative distribution service hubs within the electricity supply system. In addition, two-way communications, real-time meters, day-ahead pricing, micro-generation, appliance controls and other products have the potential to make electricity use far more efficient.

The issue in this white paper, therefore, is to determine what legal and regulatory relics of an earlier era are still present and may serve as barriers to, or enablers of, the full, economically justifiable deployment and exploitation of smart grid technology. Through an analysis of 11 states, this paper is focused on identifying those historical barriers and enablers, with an emphasis on state regulation. The rationales for those barriers and enablers are then analyzed in both a historical and policy context. The states examined for the purposes of this paper are California, Colorado, Connecticut, Florida, Illinois, Pennsylvania, Massachusetts, New Mexico, New York, Ohio and Texas. This paper then culls the lessons learned from the restructuring experience. Finally, recommendations are made for policymakers, regulators and other stakeholders in both restructured and non-restructured environments.

Examining state smart grid deployment necessitates the analysis of structural, legal and regulatory issues. Retail choice can enable meaningful demand response and promote energy efficiency. A lack of actionable information coupled with limited customer choice (i.e., monopoly environments) may yield sub-optimal efficiency gains. From this perspective, restructured states can theoretically be viewed as having a more substantial framework upon which to deploy smart grid technology and the market innovations needed to nurture it. Progressive smart grid

policy coupled with restructuring does appear to give states a head start on practices that foster smart grid implementation and enterprise.

As discussed in the state analysis section of the paper, New York offers competitive metering options and thus is actively contemplating the important issue of meter ownership. States like California and New York also have sophisticated and advanced demand-response programs that are already yielding energy efficiency savings. States like California, Texas, Pennsylvania, Massachusetts, Ohio and New York have codes of conduct aimed at lowering barriers of entry to new market participants. These codes also generally proscribe rules for the incumbent utility's handling of customer information in a competitive environment. In addition, these codes contain provisions for the privacy of customer information and provisions designed to protect customers from unsavory business practices. Several states, such as Texas and California, are actively investigating the best ways to protect customer privacy without hampering competition.

Restructured states such as Pennsylvania are leading the way in advanced meter penetration. Restructured states do face a host of implementation challenges, and successful implementation is far from clear or ensured. Advanced meter errors (or the fear of them) have threatened smart grid technology deployment projects in several regions, including California and Texas. These states also actively grapple with how to incentivize smart grid deployment (with states like Texas approving surcharges for smart meters and Pennsylvania leaning against cost recovery in some situations). These are issues that any state, whether restructured or not, will inevitably have to face. The states mentioned in the paragraph above are, however, wrestling with issues at a time when smart grid implementation is close at hand, while other states, like New Mexico and to a certain extent Colorado, are only beginning to substantively address these issues.

The head start afforded restructured states must not be taken too literally. Monopoly states also have the full potential to take advantage of smart grid technology gains and have their own structural advantages. States like Florida have made large strides toward demand response. Monopoly states may have an ability to achieve economies of scale in smart grid implementation that would not be possible in a restructured environment. To a certain extent, central control may also speed deployment in some non-restructured regions.

Strong initiative and political will on the part of legislatures and policymakers also play an important role in smart grid deployment. States like California and Pennsylvania have specific legislation that mandates, for example, that certain technologies be implemented on a tight time frame. These types of commitments add momentum and force behind smart grid technology deployment. They can also, as in New Mexico, jump-start initiatives and change the image of a state's commitment to energy efficiency. This can send positive messages to utilities and entrepreneurs looking to invest in new technologies and projects.

Of course, the foundational tools for effecting change in smart grid technology investment are regulatory levers in the form of incentives and disincentives for investment. These levers, discussed at length below, are at the forefront of smart grid technology deployment in both restructured and non-restructured states. On a macro level, traditional utility ratemaking inherently incentivizes capital investment in order to earn return. In addition and more immediately, smart grid investments offer real demand- and supply-side gains, including, for example, increased reliability and peak shaving.

There are also powerful regulatory disincentives for utilities to invest in smart grid technology. Smart grid investments by utilities may face "imprudence" designations, inaccurate depreciation schedules and protracted battles over cost allocation. In addition, traditional cost of service ratemaking discourages investments that result in reduced power sales. As discussed at length in the pages that follow, many states are implementing decoupling, rate caps, and other tools to address this, with varying confidence and success.

Further, regulated utilities tend to be risk averse, and not prone to investing in what they believe to be unproven and cutting-edge technologies. Some have contended that this has resulted in electric infrastructure not keeping pace with technological advances. Other less risk-averse players, like technology entrepreneurs or even communities wishing to aggregate load, may be more likely to play the role of innovator. Despite all its promise, smart grid technology, and marketplace innovation in general, cannot take hold without risk and the management of risk. Risk should be allocated in a way that is symmetrical to the gains to be derived, and should be managed

by the entity in the best position to do so. In addition, it is the investor, and not the ratepayer, who is in the best position to manage this risk on a day-to-day basis. Inevitably, some of the products and services in the smart grid technology milieu will be huge successes and some will be abject failures. Risk/reward symmetry ensures that all actors will be incentivized to participate and hopefully avoid expensive debacles at ratepayer expense.

Of course, incumbent utilities will generally not wish to open themselves up to competition that may threaten their business model or customer base. This can lead to the possibility of undesirable anticompetitive or manipulative behavior. The skirmishes over load aggregation in California, as discussed below, are one example of an incumbent flexing its political muscle in ways some find to be unsavory. Future battles may loom in the areas of net metering and interconnection practices, which are legally available (although to different extents) in all jurisdictions examined here.

For reasons touched on above and discussed at length below, the restructuring experience provides a useful lens through which best regulatory practices can be viewed and, hopefully, pitfalls avoided. In hindsight, restructured states, or perhaps a subset of them, relied too heavily on the theoretical promise of free markets and did not do enough to educate customers or lower barriers of entry for competitive suppliers. The restructuring debate, mislabeled "deregulation," was focused on promising lower prices and was not as open, robust or high-level as it should have been. This resulted in a lack of attention to demand-side options, poor default service design and stranded cost regimes that ultimately distorted prices. Regulators, in considering merger and acquisition proposals, historically have not always looked at the proposed symmetries being suggested on an unbundled basis, but tended to rely on the fully bundled end-result. That has tended to skew the results of reviews in ways that fail to capture specific benefits, or the risks to capture specific service benefits, that should have been examined. Thus regulators should review proposed mergers on both a bundled and an unbundled basis to make certain that all benefits and risks are fully explored in the review.

It is extremely critical in all states that customer education be prioritized. Large and small retail customers must be respected and empowered to make their own energy consumption choices if the promise of a smarter grid is to unfold. States like Pennsylvania have had some success in this area. In addition to consumer education, stakeholders must collaborate in order to make appropriate decisions on the state level that can ultimately layer with, inform and impact federal rules and policies. The need for this is particularly evident in the area of technology standardization. If technology is to seamlessly control the grid, regions will have to collaborate on some baseline functionality. States like Illinois and New York have state-wide collaboratives that are attempting to address these types of issues.

## RECOMMENDATIONS

In consideration of the information in this paper, the following recommendations are made to assist stakeholders as they make smart grid technology deployment decisions and also develop implementation strategy:

1. Customer price signals should reflect real-time costs at time of actual energy use. Utility incentives should be neutralized between demand- and supply-side resource options by tying profits to energy services provided, not simply kWh sales.
2. Smart grid investments before the meter should be recovered as fixed costs. The costs of meters and load-control equipment for customer-specific load control should be recovered on a variable basis, either as a variable cost or as part of an energy charge.
3. The risks associated with the deployment of smart grid assets should be symmetrically allocated so that those best positioned to manage assets and with the most at stake financially have the greatest potential for gain or loss.
4. All customer-specific data must belong to the customer for use as he/she determines. Aggregate system data should be considered public information.
5. Smart meters should be installed on a universal basis in order to capture their optimal benefits.

6. National standards are critical, and it is particularly important that meters and data systems are capable of bi-directional communication with customers and suppliers and can be transferred between suppliers.
  7. Customers must have a specifically enumerated set of rights, including (but not limited to) the right to: (1) confidentiality of personal information; (2) ownership of information; (3) choice of supplier and/or portfolio of supply options; (4) real-time price information; (5) appliance control; (6) install equipment to improve service quality; (7) net metering; (8) subscribe to aggregation of demand; (9) select meter and post-meter devices; (10) avoid asymmetric allocation of risk and reward; and (11) choose level of service quality.
  8. New smart grid products and programs must be evaluated to identify best and worst practices and cut losses for consumers when something has gone wrong.
  9. Utilities should receive appropriate incentives that link earnings to performance and ultimate value to customers, rather than to sales of kWh. These incentives will also induce utilities to innovate.
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# 1. Historical Barriers and Enablers to Modern High-Performance Smart Grid Deployment

## SUMMARY ANALYSIS OF BARRIERS AND ENABLERS

In looking at the state of electricity markets in a variety of U.S. jurisdictions, it seems clear that the deployment of what is commonly referred to as smart grid technology can significantly enhance overall economic and energy efficiency. Providing end-users with real-time, actionable information on prices and market conditions, as well as new ancillary service markets that value consumer action and incentivize efficiency, can enable meaningful demand response. Smart switches, smart distribution devices, automation, communications and selective redundancy can dramatically improve reliability and power quality. Indeed, even without customer choice of suppliers, as the example from Florida points out, smart grid technology can provide efficiency gains. Where a lack of actionable information is coupled with limited customer choice (i.e., monopoly suppliers), the overall efficiency gains are almost certain to be less than optimal. Nonetheless, there are clear regulatory incentives and disincentives to deploy smart grid technology for monopoly providers.

Retail choice may allow for some improvement. In fact, though, without sufficient information, efficiency gains will be limited. Even where retail markets have been nominally opened up to competition, one could argue that the changes have been of a somewhat superficial nature. Typically, customers in retail choice states are not provided with real-time, actionable information. Without the flow of real-time information, the legacy system carried over into nominally liberalized markets. The interface between customers and legacy suppliers was often not adequately addressed, particularly with regard to metering and customer information. In addition, little effort was made, most notoriously demonstrated by California, to address the disconnect between price signals emanating from wholesale market and retail prices, particularly with regard to small customers. The result is that the energy efficiency gains that one might expect from competition were not fully realized. Based on the circumstance described below, it seems apparent that there are a number of barriers to optimization. What follows is an overview of the most significant of those barriers, as well as some enabling measures that are inherent in the legal and regulatory environments described below.

### INCUMBENTS:<sup>1</sup> GIVE THEM INCENTIVES OR REDUCE THEIR ROLE?

In promoting the deployment of smart grid technology, there are two fundamentally different paths available. The first is to rely on the incumbent utilities and provide them with the appropriate incentives. The second alternative is to reduce the role of the incumbent monopoly provider and open the market up to new entrepreneurial entrants. This section analyzes those options.

For smart grid potential to be fully realized, new products and services must be able to enter the market without encountering undue barriers. While, as the example of Florida demonstrates, smart grid deployment can occur in a monopoly setting, it is not clear that the full array of benefits will be achieved unless customers are enabled to make fully informed decisions and choices regarding the acquisition and use of energy. There is the risk that, left to their own devices, incumbents are likely to make decisions consistent with their economic self-interest, which may or may not be consistent with energy efficiency. That in and of itself does not mean that incumbents do not find benefits in making smart grid investments per se. They have both incentives and disincentives for doing so.

The most basic incentive for utilities, of course, stems from the traditional utility ratemaking incentive to invest capital in order to earn a return. That incentive, of course, is not specifically targeted at smart grid investments, but it is applicable to them. However, the incentive can be offset by the fact that what is recoverable and eligible for a return is "prudent" investment, not all investment. There is also the possibility that the allowed depreciation schedule for smart grid investments will be less than adequate. The latter is particularly possible because smart

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<sup>1</sup> Over the course of this analysis, the authors use the terms "incumbent," "utility," and "LSE", or variations thereof. The terms are varied for stylistic and readability reasons, but are meant to be synonymous.

grid technology is changing so rapidly. A smart grid asset may become technologically obsolete well before the end of its actual physical life.

The prospect that regulators will look with disapproval at investments in new technology that is at risk of rapid obsolescence is, in many cases, not out of the range of possibility. First, the question of what type of smart grid technology purchases that should be made potentially becomes contestable on prudence grounds in a regulatory proceeding. Clearly, regulators have a place in evaluating the risks involved in smart grid technology investment. Regulators may also, however, be put in the position of making decisions about technological issues in areas where, traditionally, they may not have as much expertise. The risk of inappropriate depreciation schedules is also very real.

There is also the issue of cost allocation and equity in deploying new technology. Arguments are already being heard from some consumer advocates that small consumers, particularly less sophisticated ones, gain nothing from smart grid investments, and should therefore not be obliged to pay for them. To the extent that such arguments are pursued, they raise three possibilities that might dampen a utility's enthusiasm for making such investments. The first relates again to the fear of prudence disallowance. The second is concern about extended battles over cost allocation (see discussion below). The third is the possibility of inappropriate depreciation schedules. This raises the prospect of shifting costs to the most demand-elastic customers, thereby creating the possibility of losing economic load. Thus, while the incentives for making smart grid investments exist, they are not without some level of ambiguity.

A second incentive for incumbent utilities is, of course, that smart grid investments offer real possibilities for efficiency gains on the supply-side as well as the demand-side. Utilities will be able to recognize and respond more quickly and effectively to service problems, will be able to read meters and bill customers with less labor intensity, and will be able to connect and disconnect more customers. Moreover, for incumbent utilities that rely on purchased power and wholesale energy markets to procure power supply, the ability to enhance load response and reduce capacity requirements is a net plus.<sup>2</sup> In fact, with the looming prospect of increased distributed generation and plug-in cars (both hybrid and all electric), the capability for both peak-shaving and valley-filling is very attractive to most incumbent distributors of electricity. That being said, of course for vertically integrated utilities, the prospect of shedding capacity requirements and reducing spikes in demand may be less attractive than for non-vertically integrated incumbents, simply because the scale of their capital investment and the source of their profits are tipped heavily toward their investment in generation.<sup>3</sup> However, the reliability and customer responsiveness benefits of the smart grid are undeniable and should be attractive to all utilities. Much of this paper focuses on the demand side. It is clear, however, that even with no demand-side response, a smart grid has enormous advantages in terms of reliability, quality of service and responsiveness to consumer difficulties. States may wish to strengthen their reliability standards in view of the availability of technology that was not widely available at the time they were initially adopted.

A third consideration for load-serving entities in regard to any investment that leads to reduced sales of kWh, of course, is the lost revenue question. Simply stated, under traditional U.S. cost of service ratemaking, and even in such incentive schemes as price caps and other performance-based ratemaking schemes, there is a very direct link between sales of kWh and profits for load-serving entities. In short, load-serving entities have powerful financial incentives to focus their efforts on selling kWh and ignore potential demand-side efficiencies that might diminish their profitability. The result is that utility incentives can be misaligned with the public interest in energy efficiency.

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<sup>2</sup> In most jurisdictions, purchased power is simply a pass-through mechanism in which utilities have no opportunity to earn a profit, but do run the risk of a prudence disallowance by regulators. Thus, many have contended that for utilities, purchased power constitutes an asymmetrical risk with no upside but some downside risk.

<sup>3</sup> It needs to be recognized that the role of the incumbent varies widely from jurisdiction to jurisdiction. As noted above, in some states the LSEs are distribution only. In the case of the Electric Reliability Council of Texas (ERCOT) service territories, they are wires companies only, whereas in Florida they are vertically integrated. In states such as Ohio and Illinois, they are vertical but functionally unbundled. In other states such as California and Colorado, they are vertically integrated to some extent but not to the extent of their full requirements. These differences are worth noting because they bias the way that management views its self-interest in significant ways. The lost revenue issue, for example, to a vertically integrated company is a decidedly more consequential matter than to a wires company, because it has far more capital at risk.

Advocates for demand-side management have long recognized the problem and proposed that profits and sales be decoupled.<sup>4</sup> The electric rate adjustment mechanism (ERAM) described in the following discussions of California and Massachusetts are examples of the use of revenue cap methodology in which the traditional regulatory focus on the rate per unit of consumption is shifted to a focus on the total bill. This is an effort to make utilities financially indifferent to whether they fulfill their customers' energy requirements with supply or demand-side options. The theory is that regulators identify the overall revenue requirements of a regulated company and set tariffs that are, given reasonably competent performance by management, likely to yield that level of revenue. If the utility fails to recover that amount because of its efforts to promote the efficient use of the product it sold, its rates would be adjusted to better enable the company to recover its full revenue requirements.<sup>5</sup> The result may well be higher rates for the customer, but a lower overall bill because he/she is consuming less. Alternatively, where revenue caps are not put in use, regulators might also allow utilities to earn a rate of return on demand-side investments that are equal or perhaps even superior to returns allowed on supply-side options, so that demand-side investments are either equally, or perhaps even more profitable than supply-side investments. As discussed below, in Pennsylvania, PPL Corporation (PPL) recently stated that it is uncertain how to proceed with its Pennsylvania Public Utilities Commission (PAPUC) approved time-of-use (TOU) metering program for fear of lost revenue, the recovery of which is not allowed under Pennsylvania law.

Where such alternative mechanisms are in use, utilities should have no particular reluctance to make investments in demand-side efficiency measures including, but not necessarily limited to, smart grid technology.<sup>6</sup> Indeed, the fact that California uses less energy per household than any other state bears witness to the effectiveness of such incentives. While those incentives may well remove, or at least reduce, any reluctance on the part of utilities to invest in smart grid technology, it is not clear that such incentives alone will cause optimal smart grid deployment. In short, if the objective is to encourage conservation and demand response, incentives provided to load-serving entities may well accomplish much of that. If, however, the objective is to deploy smart grid in an effort to substantially reconfigure the retail market to provide more competition and customer awareness, reliance on appropriate incentives for distributors may well be insufficient to accomplish the goal.

The reason that focusing on the financial incentives of load-serving entities alone, particularly in monopoly markets, may be inadequate to make energy use more efficient is because ratemaking incentives are only one aspect of evaluating the role and interest of the incumbent with regard to the deployment and optimal use of smart grid. There are other critical questions regarding the role that incumbents play in deploying technology that enables more efficient energy markets. Those questions revolve around technological innovations and choices, access to customer databases (discussed below in section on privacy), potential for and fears of bypass and stranded assets, and customer empowerment. On these issues, the incentives of the incumbents are far more complicated than mere financial incentives. What is at stake for them are the potential risks associated with exposure to more competition, a change in their relationships with customers, and the financial and other risks associated with new technology and diminution of monopoly power.

First, with regard to technological innovation, regulated companies tend to take conservative, non-innovative paths. The basic reason for such a path is that, as regulated companies, their potential upside from innovation is almost always limited by regulated returns. Moreover, a technology failing could lead to regulatory disallowances. Thus, technology innovation has more potential downsides than upsides, an asymmetrical risk for management to take. A company could seek regulatory pre-approval for such investments. Regulators, since they are dealing with the money of the consumers they are sworn to protect, are likely to be risk-averse as well, unless there is a compelling local economic interest to the contrary,<sup>7</sup> or some other enticement such as government subsidies of

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<sup>4</sup> Some have contended that the issue is best addressed through traditional ratemaking by simply employing calculated and reasonable cost allocation shifts from fixed to variable.

<sup>5</sup> There has been some controversy over how much precision should be required by regulators to ascertain exactly how much of the shortfall in the revenue requirement was due to company conservation programs, as opposed to revenues lost for other reasons such as weather, recession, or business migration out of the territory being served. Lack of precision, of course, has been seized upon by critics of decoupling, who argue that imprecise measures of demand-side efficiency gains achieved through utility programs have led to socialization of risks best borne by utilities.

<sup>6</sup> Obviously, governmental grants, matching funds, and other financial incentives that are discussed above also serve to reduce any residual reluctance by incumbents to invest in smart technology.

<sup>7</sup> A good example of a case where regulators might be more sympathetic to technology risks is where there is a large local economic development interest in a project, such as a "clean-coal" plant in a coal-producing state.

one form or another.<sup>8</sup> Therefore, relying on regulated utilities to risk investing in technology that they will never be able to fully depreciate, whether proven types of assets or “cutting-edge” technology, is probably a mistake. Other players who have more to gain and are therefore less conservative about taking risks will need to assume a more significant role, if they can gain access to the market. In this respect, it might be instructive to look at where the innovations came from in the telecommunications market. Despite the fact that the “Ma Bell” monopoly, unlike the electric utility industry,<sup>9</sup> did maintain a high level of research and development, most notably at the Bell Labs, the real drive to revolutionize the market came from outside the regulated companies.

An excellent example of regulatory concern about smart grid investments is the Certificate of Public Convenience and Necessity (CPCN) proceeding going on in Colorado at the time of writing this paper. Xcel Energy, through its Colorado utility subsidiary the Public Service Company of Colorado (Public Service), has been working to turn the city of Boulder into a smart city, an effort that requires considerable investment, the costs of which the company will ultimately seek to recover from its customers. Requiring state regulation of demonstration projects in the form, for example, of a CPCN can be both a barrier and an enabler of smart grid technology. From a regulator’s perspective, a CPCN can help prevent unreasonable costs from being incurred and being passed on to customers. It can also help determine the appropriate amount of investment needed for a particular community. However, a lengthy regulatory CPCN process with uncertain results can clearly be a powerful disincentive to build smart grid projects.

A CPCN can, however, provide opportunities to utilities, entrepreneurs or investors. Through the mechanism of a CPCN, regulators can pre-approve cost recovery,<sup>10</sup> a powerful incentive for incumbents. CPCN approvals might also, assuming state law permits it, be a tool for regulators to open the way to new entrants by conditioning approval on some form of competitive solicitation, utility conduct, or customer choice. Indeed, CPCNs give the regulators the ability to design programs that they believe will be optimal. They could also disapprove a project entirely, of course. As Colorado regulators wade through the process, they are likely to have great difficulty ascertaining what the CPCN proceeding ought to encompass. It has been noted already that proposed “elaborate” financing and intellectual property arrangements are difficult to address. As technology advances and the many ARRA demonstration projects and approved utility plans progress, regulators will have to determine when, where and how to assume and exercise jurisdiction over them.

Another problem in unduly relying on electric utilities to adopt technological innovation is fear of where those innovations might lead. Again, the problem is rooted in the nature of the economic milieu within which utilities operate. Utilities, to their credit, recognize the necessity to think over the long term. They make capital investments for the long term, and anticipate recovery of their costs over the long life of the assets that their capital buys. Changes in the industry’s business model or environment in which they operate during the life of assets not yet fully depreciated can lead to very trying economic circumstances for utilities. As a result, they are not always as receptive to new technology as they might be otherwise.

Technology that would enable bypass through the creation of microgrids or advancement in micro-generation or battery technology, not to mention energy-saving devices or capacity avoidance programs, can have the effect of stranding assets and leaving companies unable to recover their costs. While some of those concerns can be alleviated through revenue caps or other tariff methods, or perhaps even by allowing utilities to set up unregulated affiliates that enable them to take more risks and seek more profit, the reality is that many utilities that had invested for the long term will not promote programs and technology that could lead to bottom line losses. There is a risk of generalizing and stereotyping in such an analysis, and clearly not all electric company managers think alike. The economic model in which they conduct their business does, however, create difficulties for management to pursue innovative and risky courses of action. The use of these technologies could turn out to be contrary to the company’s interest financially, even though there may be a compelling public interest in deploying

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<sup>8</sup> Regulators are very likely to be concerned about asymmetrical risk for consumers. Were they to pre-approve investment in new, unproven technology, or even new programs with proven technology, they would in effect be spreading all of the risks to consumers. If the program proves to be a failure, consumers pay. If it succeeds, other than having the benefit of its use, all other benefits, such as expertise or intellectual property, accrue to private actors who were shielded from the economic risks by regulatory pre-approval.

<sup>9</sup> The electric utility industry ranks fairly low among major U.S. industries in undertaking and supporting research and development.

<sup>10</sup> Pre-approval, of course, constitutes approval of the project, assuming prudent implementation. Any imprudence in construction or implementation is still subject to disallowance.

it. Similarly, while the overall monopoly power of load-serving entities (LSEs) has been reduced in many jurisdictions, it still exists in some form or other in every state.<sup>11</sup> This problem has surfaced already in California.

Several states, in an effort to stimulate the entry of new participants in the market and promote greater efficiency, have enabled community aggregation of load. In California, as well as in Massachusetts, Illinois and Ohio, local governments are enabled to aggregate load and choose outside suppliers. Pennsylvania has allowed for more limited aggregation. In addition to being important to municipalities, aggregation is potentially important to self generators, microgrids and other alternative generators. Recently, however, some utilities have raised objections to such efforts. Most notably Pacific Gas & Electric (PG&E), in California has aggressively opposed aggregation in its service territory. The PG&E ballot measure, discussed below, would require a two-thirds vote in order for a community to aggregate. PG&E's proposed rule is unlike Ohio's rules, which only require a majority of votes to authorize opt-out aggregation. Ohio also has much more liberal rules allowing communities to aggregate relatively easily.

PG&E's failed effort was seen by some as an effort to use the political process to interfere with markets. The company, of course, might contend that the ability of local governments to aggregate is a form of governmental interference in the marketplace. It is an example of the type of issue discussed below in terms of how incumbent utilities are likely to react to the entrance of more competition. For states, the role of the incumbent is largely a function of the nature of the retail market. Thus, in those states that do not allow retail competition, the deployment of smart grid technology and the provision of all of the services it enables is largely a function of the incentives given to and rules promulgated for distribution companies.

The complex situation surrounding incumbents, the role they play and incentives they are given to develop new products, services, and opportunities through new technology, can constitute a formidable barrier to new entrants coming into the market. Examples of the issues that flow from status of the incumbent include who owns and controls the meters, who can access customer data and under what conditions, billing operations, interface and sharing information with customers (including price information), back-up services for self generators and microgrid operators, and a host of other services traditionally provided on a bundled basis by incumbent utilities. In fact, for each of these activities the incumbent can be a facilitator and/or a competitor to any would-be provider of smart grid technology or services.

In states where the markets have not been opened up, of course, the opportunities for new providers are largely limited to load aggregators who either market their services directly to end-users or contract with utilities to provide such services. Because of significant marketing costs, not to mention difficulties obtaining sufficient customer information and setting up required back office operations, the economic barriers to entering the market (other than perhaps for large consumers) are significant. In addition, the cost of back-up services can be an effective bar to micro-generation and microgrid operations, depending on how back-up rates are calculated and the legal definitions of ability to do business within the designated service territory of an incumbent provider.

Some states have attempted to alleviate difficulties for new entrants. One area of activity has been in metering issues. One reason why restructured states were slow in generating meaningful price signals was that it was unclear who had the obligation to invest in meters. For example, would it be the local utility or alternative energy suppliers, including load aggregators? Who would do the billing? Most importantly, of course, who would get access to the data revealed by the meters and bills, and on what terms? In non-restructured states there was no such issue, as only the incumbent was in a position to deal with metering and billing. In most restructured states, those issues have now been resolved to some extent, but state regulators have struggled with the issues of what investment to incentivize or enable, and what to do with the information derived from meters and bills. There is further discussion of these issues below.

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<sup>11</sup> As the earlier discussion shows, the least-monopolistic markets are found in states such as Texas, where there is a single wires company to deliver electricity to end-users. In other states, that monopoly extends to the meter, and perhaps to billing as well. At the other end of the spectrum are states such as Florida which have vertically integrated monopolies. It should be noted that even there, the utilities may go out for bid to secure power supply from generators rather than expanding their own generating assets. In between, of course, there are other variations on the degree of monopoly power, such as mandated competitive procurement policies for LSEs and, in states with nominally open retail markets, arrangements as to how default energy supply is procured.

States have also tried to deal with the inherent market power of incumbents through requiring either structural or functional unbundling of their utilities. At the time of restructuring, those states that enabled retail competition imposed unbundling requirements on their regulated companies. In addition, because of FERC policy, most if not all states have required accounting unbundling in order to segregate accounts between transmission, generation and distribution. Restructured states fell into two basic categories regarding corporate disaggregation. Some either required or provided incentives to utilities to fully or partially disgorge their generating assets (e.g., Massachusetts and California). Other states, as well as the FERC, chose not to compel or incentivize the disgorgement of assets, but rather to impose behavioral rules that prevented distribution and transmission personnel in the same company from providing information to their generating affiliates unless they provided the same data on the same terms and conditions to all interested generators.

Those two approaches are the traditional means by which regulators attempt to control the undue exercise of market power. Incumbent utilities may in many ways be facing the same issue they did with generation, in regard to their distribution activities, namely wires, metering, billing, and demand-side services. While the wires business is likely to remain a monopoly (although the potential for distributed generation and microgrids may diminish some of that monopoly power), the other services may well be contestable. It is not yet clear exactly what paths the states will take on these matters, but there are insights based what they have done in the past.

Mandated corporate restructuring and disgorgement of certain types of assets is the most dramatic response to market power, and undoubtedly the easiest to enforce. Its use as a weapon to combat market power, however, is often constrained by other considerations such as tax consequences, credit and collateral arrangements. As a result, behavioral codes of conduct, which are more difficult to enforce, are often put in place to restrain the exercise of market power and to level the playing field between incumbent utilities and new market participants.

Typically, these codes establish competitive safeguards for interaction between electric distribution companies, electric generation suppliers and customers. Connecticut, Illinois, Pennsylvania and Texas are examples of states that follow this approach. Illinois' code of conduct is less mature, and does not yet require mandatory disclosure. Pennsylvania's code of conduct includes a specific prohibition on illegal tying (when an incumbent requires a customer to purchase additional services as a condition of receiving one kind of service). Those experiences, of course, are mostly related to what happened to generation in the original restructuring. They may have to be revisited as we look toward the possibility of further opening of the retail markets by smart grid investments.

## **CONSUMER PROTECTIONS AND PRIVACY**

Consumer protection rules are also present in both restructured and non-restructured states. These rules provide opportunities to increase the flow of information to customers and also create a fair marketplace for consumers and suppliers. As such, they can play a key role in customer education and key elements of a fair smart grid. New Mexico, for example, requires that bills be unbundled and made more transparent by noting which costs are attributable to generation, transmission and distribution activity. This will assist customers to better understand their service costs.

Consumer protection rules typically include mandatory disclosure statements and requirements on contracts and the contents of bills. These are clearly important aspects of a competitive services market and can foster the development of the smart grid. Customers should be able to understand what they are committing to in their contracts, what charges are incurred and what their rates will be. Required disclosure statements like those in Ohio, usually must contain the terms and conditions for service and pricing, including when a customer can switch to another provider. Pennsylvania requires that the terms and conditions of variable pricing, when applicable, must be stated. States have varying rules on the time period a customer has to cancel a contract. In Pennsylvania, a customer can cancel a contract until 3 days after disclosure has been given. In Illinois, a customer can cancel within 10 days of accepted enrollment without an early termination fee.

Consumer protection rules also include provisions on customer information and privacy. There is some tension between the development of markets and the right of customers to keep their information private. To optimize the use of smart grid technology, of course, such data as patterns and purposes of customer use of electricity is essential information for both the customer and any entity providing him/her with smart grid services. Many states

require some kind of customer consent before a utility can release a customer's personal information. States like California, Colorado, Pennsylvania and Ohio have requirements that utilities must receive customer consent to release it to authorized third parties.

Massachusetts has recently enacted some of the nation's most detailed privacy laws, which include data collectors outside of the state. To date it is unclear how the new law will affect smart grid deployment in the state and beyond, except that it is clear in most jurisdictions that utilities will not be able to share information with other entities without the consent of the customer. How the utility itself uses that information varies under state law. The desire to protect consumer privacy, of course, is an understandable and legitimate public policy objective. The problem is that it can also constitute a barrier to end-use efficiency gains and market entry for new smart grid players, or badly skew the competitive balance in the direction of the incumbent.<sup>12</sup> One obvious solution is to provide customers with all relevant information and let them decide what to do with their own data.<sup>13</sup> Several states have attempted to address the issue. In most states, rules requiring customers' consent to information provide the customer a certain amount of ownership of their data.

Restructured states often have rules requiring that incumbent utilities share information in a way that is not discriminatory to new entrants. In Connecticut, for example, a utility can release certain information to an affiliate without customer consent if it does so in a non-discriminatory way. This measure addresses the issue of unfair competitive advantage, but may not be sufficiently protective of customer privacy. In California, when a customer authorizes third party access, the customer automatically consents to that third party receiving other information it needs to meet its obligations. Consent in California can be given through electronic signature. California's third party access consent attempts to find a middle ground between enabling markets and protecting consumers. Florida uses a "reasonableness" standard for information requests to utilities by customers. Colorado is now investigating how often customer consent will be required before a utility can share information.

## PRICING

Without appropriate pricing, much of the demand-side value of smart grid technology will be lost. Indeed, the case for making smart grid investments will be weakened considerably. Since the only price signal a customer receives is an end-of-the-month bill, there are few if any meaningful price signals to direct customers and efficient service providers to where savings and efficiency gains can be made. Pricing that does not reflect the reality of usage patterns generally distorts actual prices and has the net effect of causing customers to miss opportunities for end-use efficiency gains. Similarly, common regulatory tools like rate stability plans, average-cost pricing, cost socialization, and "normalization of rates" contribute mightily to both market and energy inefficiency, and render investment in smart grid technology less attractive. It is clear, however, why regulators have implemented these measures. "Rate shocks" bring social costs and often political turmoil. Stability and reliability of service is essential to consumers and the public at large. Similarly, socializing costs rather than trying to identify cost causers, and using average-cost pricing, is less complex and usually less controversial than trying to design more accurate and appropriate price signals. While such practices are understandable, they serve as barriers to the adoption and deployment of smart grid technology that rely on "smart" signals to help justify the cost of investing in it. That being said, if traditional average-cost pricing is deployed based on actual load profile, then customers in such a regime could still sell demand reduction into day-ahead markets.

Time-of-use (TOU), real-time and day-ahead pricing should be enabled to promote market efficiency generally and smart grid deployment specifically. To the most reasonable extent possible, costs should be allocated to those customers who incur them. It may be posited that markets for key smart grid components like smart chips in appliances and machines, micro-or distributed generation, microgrids, home area networks (HANs) and smart appliances, will never be realized unless consumers can receive and react to meaningful price signals. To alleviate these gaps in the flow of information, states like Connecticut, California, Illinois, New York and Pennsylvania have mandated TOU and/or real-time pricing. Others, such as Texas and Colorado have not, although Texas has approved major investments in the metering technology that will enable the use of such

<sup>12</sup> The skewing is actually in favor of the entity controlling the meter and data it reveals. In the overwhelming majority of states, that is the incumbent utility.

<sup>13</sup> The most useful data, of course, is consumption data, such as time of day and seasonal usage, bills, appliances and other uses of electricity on the customer's premises. The level of data detail is also a feature of the meter technology in place.

information, and it remains to be seen what Colorado will do in the course of the CPCN proceeding it has under consideration.

## METERS AND COST RECOVERY

New technology demands innovation and flexibility. The traditional utility meter could last one or more generations of customers after installation. Calculation of cost recovery of prudent meter investments was relatively straightforward. Comparatively, the physical life of new advanced meter infrastructure (AMI) is far less certain. State commissions have sought to strike a balance between preventing undue risk while not arbitrarily denying utilities the ability to recover costs.

Texas, for example, has instituted recovery charges for new meter installations, effectively socializing the cost of AMI.<sup>14</sup> Socializing the cost of AMI can speed deployment, but it can also dilute price signals. It can also have the effect of allocating the costs of new technology to a subgroup of customers who may not want it.

In addition, the advantages of smart meter infrastructure must be weighed with the consequences of delaying its rollout. Texas, in the face of customer concerns about the accuracy of new meters, was asked to delay or postpone their rollout. The Public Utility Commission of Texas (PUCT) chose to allow deployment while allowing for testing of the new meters by an independent third party. New Mexico, in contrast, has rejected a meter replacement surcharge. It should be noted that the accuracy of smart meters should prove to be a growing concern as states achieve more meter penetration. California, for example, is also grappling with the need to test meters (see the below discussion of allegations that PG&E's smart meters are inaccurate). This further attests to the unpredictability of the shelf life of new technologies. One counterbalance may be for more states to adopt dispute resolution rules, such as those currently in Florida.

States may wish to consider allowing consumers to buy advanced meters from third parties to a standard specification. Ensuring that advanced meters or other devices are priced properly, however, can be difficult. As discussed below, in Pennsylvania, consumers who elect to pay for early installation of smart meters face a wide variation in meter prices. Some communities pay for the meters by combining them with a demand-response program that generates sufficient savings to pay for the meter. Similarly, utilities in competitive markets may find that competitive suppliers will bundle cost-savings services with advanced meters.

## NET METERING AND INTERCONNECTION

Net metering and interconnection policies that support energy efficiency and alternative generation are a key component of the smart grid. Of the states surveyed, the majority had state-wide net metering and interconnection policies in place. Pennsylvania's net metering rules, which are discussed below, allow for both physical and virtual net metering and are particularly progressive. Texas, however, is an outlier, in that while it allows for voluntary net metering, it does not have a state-wide net metering policy. The lack of net metering policies in Texas has been attributed to H.B. 3693, which required net metering but failed to define it adequately.<sup>15</sup>

## STAKEHOLDER COLLABORATION AND ADVOCACY

A smart grid, like cell phones or the Internet, is socially transformational technology and will change the human experience with electricity.<sup>16</sup> The challenge is to integrate automation systems within and between the electricity delivery infrastructure, distributed resources and end-use systems. This will require new solutions for existing interfaces that embrace best practices and interoperability across all sectors of the American economy. Thus, greater interaction among all stakeholders is a "necessary characteristic" of a smart grid.<sup>17</sup>

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<sup>14</sup> This was, in part, justified because all affected customers were in competitive markets.

<sup>15</sup> Freeing the Grid, the Network for New Energy Choices, Nov. 2009 at p. 10, available at: [www.freeingthegrid.com](http://www.freeingthegrid.com).

<sup>16</sup> DOE Smart Grid Report (July 2009) at p. iv.

<sup>17</sup> *Id.*

Several of the states examined have held informal collaborative and commission- sponsored workshops to form their smart grid policy. Illinois in particular has established a formal, statewide smart grid collaborative. Stakeholders can also be effective as advocates that bring key issues and recent developments to the attention of regulators. An illustration of the importance of stakeholder action is in the Colorado Public Utility Commission (COPUC) privacy issues investigation discussed below. The investigation was in part spurred by the report of a law student who helped bring the issue to the attention of the COPUC. Thus, stakeholder collaboration and stakeholder advocacy have a large role to play in the development of a smarter grid.

## 2. Overview of Federal Legal Changes to the Bulk Wholesale Markets Since the Passage of the Energy Policy Act of 1992 (EPAct)

Over the past 30 years federal policy, both at the Congressional and regulatory level, has been to promote and nurture competitive bulk power markets. The policy was begun somewhat inadvertently by Congressional passage of the Public Utility Regulatory Policies Act (PURPA) in 1978. PURPA required utilities to purchase power from Qualified Facilities (QFs) at their “avoided costs,” a figure state regulators were compelled to ascertain. Many states took aggressive steps to promote the use of QFs—so aggressive, in fact, that in a number of states the amount being paid to such generators grew to exceed market prices. Indeed, many investors saw such attractive possibilities that they built what came to be called “QF machines,” a term used to describe generating facilities designed to look like co-generators, even though they really may have been something else. While that phenomenon did not occur in many states, the problem reached such dimensions that in the late 1980s the FERC stepped in to require that “avoided cost” calculations not be administratively determined, but rather be ascertained through competitive solicitation.

The PURPA experience opened doors to competition in generating capacity. That competition, however, was limited by two key factors. The first lay in the provisions of the Public Utility Holding Company Act (PUHCA), which included powerful incentives against the ownership of generation by a single corporate entity across state lines and/or which were not fully integrated into a single system. The second factor was the inability of non-utility generators to access the grid in order to sell power. Both of those limitations were swept away in 1992 by the EPAct, which gave the FERC the authority to mandate transmission access on a case-by-case basis, and by the creation of Exempt Wholesale Generators (EWGs), which allowed generating companies to avoid the restrictions found in PUHCA.

The FERC took the matter even further in the years subsequent to the passage of the EPAct. The FERC required all transmission-owning utilities to file *pro forma* open access tariffs. The FERC also encouraged the formation of RTOs and/or Independent System Operators to enable the transfer of energy over wide geographic footprints under a single tariff and under one consolidated operator. Additionally, where the FERC found that a generating company did not possess market power, it loosened the regulatory oversight of pricing by allowing market-based rather than cost-based rates. The FERC also encouraged the evolution of more precise price signals in the marketplace by encouraging locational marginal cost transmission pricing, day-ahead markets and real-time prices. While some regions of the country, primarily the Southeast and Northwest, resisted those FERC initiatives, they became reality elsewhere. Additionally, in 2005, Congress repealed PUHCA and the limits it imposed on utilities.

What is important to note is that federal policy has evolved in a consistent manner not only to promote competition in the power sector, but also to produce very sophisticated pricing and signaling that serve to enrich the competitive nature of the industry. For those signals to reach the end-users that the system is ultimately designed to benefit, however, would require action by the states that retain the power to regulate retail markets. The precise steps FERC and Congress took are in the outline below.

- I. FERC Initiatives and policies post ,92 Energy Policy Act:**
  - A. Order 888**
    - 1. Mandates open access transmission service
    - 2. Encourages Independent System Operator formation
  - B. Order 2000**
    - 1. Encourages RTOs
    - 2. Further reduces the effect of “pancaked” rates and “seams” between control areas
  - C. Standard Market Design Rulemaking**
    - 1. Imposes a standard market design
    - 2. Imposes locational marginal pricing
    - 3. Asserts jurisdiction over the transmission component of bundled retail service
- II. State policies/experiences on retail markets post ,92 EPAct**
  - A. Divestiture and deregulation**
  - B. Western energy crisis / subsequent ring fencing**
  - C. Retail competition and choice**
- III. 2005 Energy Policy Act (EPAct 2005)<sup>18</sup>**
  - A. States must consider the introduction of smart meters and variable pricing<sup>19</sup>**
  - B. Incentives for demand response<sup>20</sup>**
  - C. Incentives for implementation of advanced transmission technologies**
  - D. Repeals the PUHCA**
  - E. Creates a minimal Federal role for transmission siting**
- IV. 2007 Energy Independence and Security Act (EISA)**
  - A. Defined the objectives and characteristics of the smart grid<sup>21</sup>**
  - B. Accelerated the development of the smart grid through studies on regulatory barriers, development of national technical standards and funding<sup>22</sup>**
- V. 2009 American Recovery and Reinvestment Act (ARRA)**
  - A. \$4.5 billion in funding for smart grid and demand response projects**
  - B. Funding of up to 50 percent of the cost of certain projects**
  - C. Funding of up to 50 percent of the cost of demonstration projects**
  - D. Funding of projects through private banks or the Federal Financing Bank**

<sup>18</sup> Eli Farrah and Sonia Mendonca, “Federal Issues in Smart Grid Regulation,” Dewey & LeBoeuf internal presentation (2009) (on file with author).

<sup>19</sup> EPAct 2005 § 1252.

<sup>20</sup> *Id.*

<sup>21</sup> EISA § 1301 states that the following together characterize a “Smart Grid”: (1) increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid; (2) dynamic optimization of grid operations and resources, with full cybersecurity; (3) deployment and integration of distributed resources and generation, including renewable resources; (4) development and incorporation of demand response, demand-side resources, and energy-efficiency resources; (5) deployment of “smart” technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation; (6) integration of “smart” appliances and consumer devices; (7) deployment and integration of advanced electricity storage and peakshaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning; (8) provision to consumers of timely information and control options; (9) development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid; (10) identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.

<sup>22</sup> EISA §§ 1302 and 1303.

- E. Tax benefits and loan guarantees for other areas in the energy sector—overall more than \$30 billion under the control of the U.S. Department of Energy (DOE)
  - F. Funding<sup>23</sup>
    - 1. Amounts available are small in light of the number of projects—the consumer portion of the investment will still be significant
    - 2. Difficulties associated with the solicitation process for grants and loan guarantees
    - 3. Complex proceeding
- VI. Primary entities involved in the implementation of the smart grid**
- A. DOE
  - B. FERC
  - C. National Institute of Standards and Technology (NIST)
  - D. States
  - E. Departments of Defense, Interior, Treasury, Homeland Security, Agriculture, Environmental Protection Agency; Federal Communications Commission
  - F. Federal regulatory initiatives
- VII. Funding**
- A. Grants
  - B. Loan guarantees
  - C. Public-private partnerships
  - D. Tax benefits
  - E. Coordination of task force
  - F. Information clearinghouse
- VIII. NIST—Coordination of the process for developing technical standards for interoperability**
- A. Roadmap published with initial standards and plans of action<sup>24</sup>
  - B. Smart grid equipment is already being developed and installed without the benefit of final standards
  - C. Need to develop a system of testing and certification to ensure interoperability of the equipment
- IX. FERC**
- A. Jurisdiction—traditional FPA jurisdiction and EISA jurisdiction (adoption of technical standards and protocols relating to the functionality and interoperability of the grid)
  - B. FERC Policy Statement (adopted July 16, 2009)
    - 1. Defines the priority issues that should be the initial focus of the standards development process coordinated by NIST
    - 2. Addresses security
    - 3. Fosters communication and coordination through the interfaces of the various systems that comprise the smart grid
    - 4. Creates wide-area situational awareness

<sup>23</sup> For information on ARRA funded projects, see the DOE web site at: <http://www.energy.gov/recovery/index.htm>.

<sup>24</sup> See *NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 1.0*, Office of the National Coordinator for Smart Grid Interoperability, Jan., 2010, available at: [http://www.nist.gov/public\\_affairs/releases/upload/smartgrid\\_interoperability\\_final.pdf](http://www.nist.gov/public_affairs/releases/upload/smartgrid_interoperability_final.pdf).

5. Addresses demand response
6. Addresses integration of storage technology
7. Integration of electric vehicles
8. Defines interim rules for cost recovery to be effective until the adoption of technical standards

**C. Rate Policy and Cost Recovery**

1. Interim rate policy for transmission cost recovery (FERC Policy Statement)
2. Allows the recovery of jurisdictional smart grid costs if certain showings are made through either a petition for declaratory order or a limited FPA section 205 filing
3. Effective until relevant interoperability standards have been adopted through FERC rulemakings

**X. Major federal issues**

**A. Privacy**

1. FCC model may apply to the Smart Grid
2. EISA requirements

**B. Security**

1. Smart grid will introduce points of access to information that are outside of the environment controlled by utilities, which will leave the bulk power system more vulnerable to attacks
  2. FERC has stated that the North American Electric Reliability Corporation (NERC) cybersecurity standards may not cover all types of smart grid equipment
  3. Although the NIST standards will incorporate the cybersecurity standards, it is not clear that FERC would have jurisdiction to enforce the NIST standards directly
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### 3. Policy Context and Recommendations

In considering appropriate policy recommendations for full deployment of smart grid technology, it is important to first set the context within which recommendations are being made. The first context is the historical one, namely analyzing the lessons that have been learned for restructuring to date, in order to ensure that we do not repeat the mistakes made in the past decade or two while reconfiguring the nation's power sector.

The second context is dealing with the reality that the electricity industry structure in the United States today, while diverse, is fundamentally bipolar, divided between jurisdictions and regions that have moved toward competitive markets and those that still retain the vertically integrated monopoly model. Given that divide, it is difficult to offer a single set of broad policy recommendations with universal applicability. This section examines smart grid policy in both the monopoly and competitive supplier contexts, including the "upsides and downsides" to each model. For reasons that will be clear in the discussion that follows, the policy recommendations are largely made in the context of long-range objectives, while recognizing that they may play out differently from one jurisdiction to another.

#### LESSONS LEARNED FROM HISTORY OF RETAIL RESTRUCTURING

In discussing the lessons learned from retail restructuring, it should not be concluded that restructuring and moving toward a more competitive market was, as a general proposition, bad public policy. On the contrary, the traditional reliance on a monopoly model has many drawbacks that made and continue to make it ripe for reform that would allow, indeed encourage, competition. The monopoly model is not well-suited for innovation in the deployment of technology or the provision of goods and services. It makes customers captive to single producers, who may or may not have been efficient and reliable suppliers, and subject to the vagaries of a regulatory process rather than a customer-focused market. It also tends to frequently pass on risks to consumers more quickly than a competitive market would permit. Thus a critique of the way in which restructuring was carried out should absolutely not be read as a call for maintaining the monopoly model, or for deferring market reform. Rather, it is meant to point out important lessons to be learned from the restructuring experience so that we are not doomed to repeat them, as we move forward with new technology that promises to create a more efficient power sector.

The restructuring in the electricity industry that has occurred over the past two decades has proven instructive on a number of levels. There are many lessons to be derived from the experience. As noted elsewhere in this paper, there has been considerable success in making wholesale markets more competitive in many, although not all, regions of the U.S.

These successes should not be overlooked or underestimated. The development of very sophisticated organized regional markets in many parts of the United States has been an extraordinary accomplishment, and its individual elements are too numerous to recount fully herein. Worthy of particular note, however, are: (1) highly competitive wholesale markets; (2) sophisticated market instruments that add considerable liquidity and richness to markets; (3) elimination of transmission barriers to market evolution; (4) efficient pricing of transmission constraints; (5) bringing demand-side bidding into its rightful place in the marketplace; (6) sending real-time price signals on a consistent and meaningful basis and pricing ancillary services; (7) removing market power barriers to competition; (8) adding considerable transparency to historically opaque marketplaces; and (9) making energy markets more efficient.

There have also been successes at the retail level, particularly in industrial and commercial markets. Meaningful competition has replaced special administrative determinations and contracting for pricing service to large industrial consumers. Energy service companies have been able to enter the market and offer energy efficiency gains previously not available to customers. Alternative suppliers have also been, in many cases, able to offer products and services unavailable in previously closed retail markets. Results of retail market restructuring, however, if measured by how many customers have fully availed themselves of retail choice, have proven in many cases, with Texas perhaps a notable exception, to be less than fully successful, particularly in regard to small commercial and residential customers.

In regard to the deployment of smart grid assets, however, that mixed record is important to note. Many, although by no means all, of the benefits associated with the deployment of smart grid will be jeopardized by the absence of appropriate retail choices, particularly in regard to pricing. On the other hand, and, perhaps more importantly, the lack of full success in retail competition is also due, in no small measure, to the absence of the type of technology being offered up as smart grid. Those missing include technologies that enable meaningful, real-time price signals, and efficient, response by consumers to those signals. They also include the ability to provide improved service quality, including enhanced reliability, that was not available before. Therefore, the lessons learned from over a decade of retail market reform merit some attention in order to set out appropriate and attainable policy recommendations that both acknowledge the lessons of the past, good and bad, and apply those lessons in the relevant technological and economic context of the present day.

Indeed, there are many ways in which markets can be restructured, and it is important that we learn what has been done well and not so well, so that as we move forward, we do so with the greatest possible prospect of success. While there are a large number of lessons to be learned, the following is a list of those that most need to be taken into account before investing in and deploying smart grid technology at the retail level.

1. First and foremost is getting the pricing right. Few of the states that restructured retail markets changed the basic pricing regimes away from average costs (i.e., averaged by class and heedless of real-time costs and wholesale prices). While industrial and large-scale commercial customers were given more pricing options, for the most part neither small commercial or residential customers were provided with any significant additional pricing flexibility. In addition, would-be market entrants who might desire to serve them were provided few, if any, new tools to entice customers away from incumbents.<sup>25</sup> Perhaps even more problematic, many states, by law or regulatory fiat, de-linked retail and wholesale prices. Thus customers were literally prevented from seeing the very sophisticated and meaningful real-time prices generated in the regions with well-organized wholesale markets. The de-linking of wholesale and retail prices was most notable in California, where it was one of the critical factors that led to the implosion of that market. Many other states committed the same error, albeit with less catastrophic results. In essence, however, the failure to reform retail electricity pricing was a virtual guarantee that restructuring would be more superficial than it should have been, and increased the likelihood that the desired results would not be attained. The failure to reform pricing as part of the restructuring could be categorized as policymakers weakening the foundations of the new market at the very time they were attempting to build them. The implications of correct pricing for smart grid are enormous. While there are clear supply-side benefits from the deployment of the technology, particularly in meter reading, service connections and disconnections, reduction in non-technical losses, and service quality, there are also perhaps even greater benefits to be derived from the demand-side, particularly as we look ahead to plug-in hybrid cars and other new demands on the system. If we repeat the same pricing mistakes made in the original restructuring, we will essentially be foregoing many of these benefits and impose even greater burdens on the system than necessary. The fact is that smart grid assets not only provide greater value with the correct pricing, but, perhaps even more importantly, smart grid gives us the ability to better establish efficient pricing than ever before. Getting the pricing right is always important, but we are now better positioned to do it than we have ever been, with more to gain from doing so.
2. The second error also flowed out of the same tepid approach to restructuring that resulted in a failure to address pricing. Policymakers in most restructured states, with the noted exception of Texas (and perhaps Ohio and Massachusetts, which enabled municipal aggregation), apparently concluded that the removal of legal barriers to the entry of competitive energy suppliers would be sufficient to create a competitive retail market. In short, the philosophy seemed to be "if you open the markets, they will come."<sup>26</sup> That turned out to be a serious underestimate of the significant entry barriers for potential suppliers. Enormous marketing expenses, inability to offer the types of new products and services that more meaningful pricing would have yielded, poor design of default service offerings, ingrained consumer

<sup>25</sup> The most notable exception to this was in Texas where the incumbents were essentially denied the right to serve customers in the territory in which they provided retail delivery service.

<sup>26</sup> It is worth noting that in the original restructuring legislation in Ohio, the sponsors foresaw the entry barriers, so it was proposed that customers be bundled into units of 100,000 each, for whom the default service obligation would be auctioned off. That proposal was abandoned after one State Senator proclaimed such an auction to be a "badge of slavery" that was outlawed by the 13<sup>th</sup> Amendment to the U.S. Constitution. As one wry observer noted, "it must be the Senator's view that captivity to a monopoly constitutes freedom."

habits of relying on monopolies, and a host of other barriers were far too great for most alternative suppliers to overcome for customers, other than those with very large loads. In hindsight, it is clear that there was a failure in most restructured jurisdictions to either remove or sufficiently mitigate the barriers to competitive entry. The deployment of smart grid technology offers even more possibilities for opening up retail markets, as it would enable easier entry and operations for load aggregators and new suppliers. It also invites reopening the question of who owns and operates meters, as well as providing a better likelihood of the type of information symmetry that can enable new entry.

3. Ignoring demand-side options was a serious blunder that in hindsight is difficult to understand. While one might explain the terms as part of a reaction against least cost planning, it is nevertheless mystifying how advocates of competition could ignore demand response as an absolutely critical element of efficient markets. The de-linking of retail prices from wholesale market realities, the arbitrary fixing of retail tariffs (i.e. default service) to make it appear that opening the markets had, in fact, produced lower, or at least not increased rates, and the fixation on assuring recovery of stranded costs, as well as other manipulations, all served to diminish both the opportunity and incentive for promoting energy efficiency. While it must be said that there is now, particularly in the organized RTO markets, a growing appreciation for, and effort to obtain, energy efficiency gains and demand response, clearly those efforts are coming years after they should have.. While it could be argued that one reason for the inadequate attention to demand-side possibilities was lack of technology to provide real time price information to customers, that argument disappears with the deployment of smart grid assets, and proper attention to end use efficiency and load management is enormously facilitated. There is simply no reason for repeating the mistake of not fully capturing energy efficiency gains.
4. A major focus of restructuring was to enable the recovery of utility “stranded assets.” That focus on socializing costs caused a variety of distortions.<sup>27</sup> The first was that it set a precedent of sorts that incumbents would be partially, if not entirely, insulated from risks in the new competitive market. Second, the recovery was premised on an assumption that prices would go down because of increased competition, and that utilities would be unable to recover the full costs of investments in regulated assets. That premise has proved to be largely incorrect and has led to a number of market and price distortions. Some, though not all, restructuring jurisdictions required that utilities divest themselves of generation in order to either establish the baseline for stranded cost recovery, or in order to qualify for recovery at all. The results of mandated divestiture, particularly where there was pressure to maximize the prices obtained, was that fleets of plants rather than individual plants were sold, which meant more consolidation of market power than desirable for the competitive environment being sought. It also set the baseline for stranded cost recovery based on a random snapshot in time, as opposed to a more measured and calibrated methodology. In those jurisdictions where divestiture was not required, but where stranded cost recovery was permitted, the market was distorted by allowing utilities to sell energy from plants whose cost recovery was artificially accelerated through regulatory means, in direct competition with generators who lacked those same competitive advantages. Thus, with or without mandated divestiture, stranded asset recovery reduced the overall competitiveness of the market. In terms of equity, as demonstrated by recent controversies in Illinois and elsewhere, many customers came to believe that in paying for stranded asset recovery and then paying for higher prices in the competitive market, they were being required to pay twice for the same assets. That perception has caused a fair amount of market disruption that could well have been avoided. The experience demonstrates that we need to carefully consider the consequences before we decide how to allocate risks between investors and the public. Utilities may well fear that substantial investment in assets whose physical life is in excess of its technological usefulness leaves open the possibility of either stranding some portion of the investment or forgoing timely technology innovation. It is also clear, however, as noted in this paper, that there are choices regarding cost recovery and risk allocation that avoid the stranded asset question entirely, and should be pursued.
5. In the many states that seriously debated restructuring their retail markets, debates over the meter and access to customer information were common. For the most part, it was determined that the distribution utility would continue to install, maintain and own the meter, and would do all of the billing and collections.

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<sup>27</sup> Stranded assets were defined as the difference in the value of an asset in the regulated environment in which it was built and its value in the subsequently created competitive environment. For utilities, recovery of that difference was a matter of fairness and equity and what they called the “regulatory compact.” For many advocates of competition, allowing stranded asset recovery was viewed simply as the political price to pay for buying off utility opposition to restructuring. One advocate of competition described it as the only time public officials were caught paying bribes to private companies. For some consumer groups, it was seen as a “rip-off.” While the debate over stranded asset recovery was often heated, the utility point of view prevailed in every jurisdiction.

In many ways the utilities, which wanted to retain control over the meter, prevailed by default, since they were the course of least resistance for a variety of reasons. These reasons include a pre-existing relationship with the customers, the fact that changing out meters would be an expensive exercise likely to leave still more assets “stranded,” and the belief that local utilities could best protect the privacy of customers. In hindsight, that decision may not have been thought out as carefully as it should have been. Perhaps from the current perspective, the meter issue plays out in an entirely different context. With the evolution of metering technology whose useful life is probably shorter than its physical life, one questions whether utilities, who are accustomed to long-term capital recovery over the life of assets, are best suited to manage the risks associated with meter and control technology. Moreover, regulations to protect privacy are now so widespread that there is less reason to believe that local utilities are any better suited to protect privacy than other service companies. It would also have been useful in the restructuring debate to ask whether or not the meter and associated costs, from an economic and efficiency perspective, are best tied to the energy and energy service provider, or to the delivery/wires company. Similarly, there was little or no debate over whether the costs of meters were appropriately recovered through fixed or variable charges. They were simply assumed to be a fixed cost. That aspect, as important as it is, was almost entirely missing from the restructuring debate. As we move forward with more dynamic metering and control technology, that debate must no longer be permitted to remain “below the radar.” It should be renewed, and decisions reconsidered in the context of smart grid technology and the opportunity it offers.

6. Restructuring electricity came after a debate that can, in almost every jurisdiction, charitably be described as less than intellectually honest. Advocates on all sides of the debate were frequently oversimplifying issues, making false promises, inaccurately characterizing existing and prospective circumstances, and failing to educate both policymakers and the public. The question of how to reconfigure a core infrastructure industry, perhaps society’s most capital-intensive one, was not debated with the attention and thought that the gravity of the subject merited. In fact, there are several examples of the debate showing flawed results with negative repercussions. There was, as noted, the naked assertion that competition would drive prices down, as if Newton’s Laws of Physics somehow applied to the economics of electricity. In many states, prices were arbitrarily frozen (e.g. California) or even lowered by simply deferring cost recovery and calling it a “decrease” (e.g. Massachusetts). These were, in essence, artificial contrivances employed to “prove” that competition would lower prices. To make matters worse, the very fact that rates were artificially frozen or reduced actually had the effect of destroying the headroom required to enable competitors to enter the market. Policymakers by fiat lowered prices (in the short term at least) to levels where no competitor could enter the market, perhaps the least desirable result if one is looking to promote competition and market efficiency. Making the debate even less forthright was the fact that it was often framed as a discussion of whether or not to deregulate the industry, when in fact no serious proposition was ever put forth which would have “deregulated” electricity markets. All serious participants in the debate recognized that some aspects of the business, particularly the wires component, were an essential bottleneck where regulation would endure. Similarly, anti-trust regulation in generation and perhaps in retail supply as well was viewed as an essential element of reform. Using the term “deregulation” not only mischaracterized the issues, but also tended to distort them by painting matters with a broad brush that swept away the subtleties of restructuring. This allowed ideologues of all stripes to slug it out without much consideration of the subtleties and nuances characteristic of electricity markets. The mix of politics and electricity, while perhaps unavoidable, is less than ideal for the intelligent formulation of policy, but it is critical that the participants in the debate enlighten rather than argue and distort the issues. Unfortunately that was often not the case, but that historical misfortune need not be repeated.
7. As noted above, some of the manipulations regarding stranded assets resulted in a failure to decrease the consolidation of market power in regional markets in generation. Although that may have resulted in less competition and fewer players than desirable, the inordinate exercise of market power in the organized RTO regions was largely precluded by the presence of market monitors and rules that mitigated market power. None of that mitigation took place in the scrutiny of market power issues at the retail level. The design of default service was, with a few exceptions such as Pennsylvania, set out without much consideration of what effect the default service design would have on competitive entry into the market. In almost every case, with the notable exception of Texas, the local distribution utility was designated as the provider of default service. On merger and acquisition activities, while federal

regulators conducted reasonably diligent market power inquiries regarding generation, state regulators for the most part exercised considerably less scrutiny on the retail service side. Perhaps even more important, few if any state regulators looked at the synergies being claimed by merging entities on an unbundled basis. Thus, the synergies claimed were not examined on a service-by-service basis, but rather an overall basis. For example, while two merging distribution utilities may well have economies of scale in regard to the wires business, they may not have them in the retail supply business. The absence of that sort of careful analysis may well have constituted a lost opportunity for advancing the competitiveness and contestability in retail markets. The fact is that smart grid offers the very real possibility of many new entrants into the electricity market, many of them with the means to be formidable competitors, so the potential exists for making more robust competition in electricity markets.

8. Another lesson to be learned was that there was not enough effort put into making consumers aware of their options. There were two fundamental problems. The first, as noted above, was the amount of disinformation that flowed from both the debate over restructuring as well as the price signals given out by the manipulation of rates. The second problem was that efforts to educate consumers about their choices and opportunities were, in many cases, inadequate to produce the consumer activity envisioned by proponents of competitive retail markets. Any major market changes, particularly where the change is from a monopoly setting to a competitive one, needs to be accompanied by a serious effort to educate consumers. Consumers can only take advantage of the opportunities offered them when they are provided, in user-friendly ways, with adequate information. This information includes meaningful and timely price signals, tools to respond to those signals, and a knowledge base to act from. The same lesson would apply to the deployment of important new technology and how to optimize its use. Smart grid technology is a very powerful tool for both educating and enabling customers to be more efficient users of energy. Its deployment must be accompanied by very substantial efforts to educate the public on how to avail themselves of it. Indeed, the entry of powerful new players in the market enabled by smart grid will inevitably result in major marketing efforts that seem likely to produce a far better informed public.

## THE MONOPOLY SUPPLIER AND THE COMPETITIVE SUPPLIER

Any discussion of retail electricity markets in the U.S. must start with the recognition that there is little national policy guidance for these markets, and that retail market design is a function of policymakers and regulators at the state level. While one can debate whether the enactment of national policies for retail markets is desirable or not, the fact is that, other than at the margins,<sup>28</sup> they do not exist. Because the states are split as to whether retail markets are contestable, it is clear that recommendations regarding policies governing the full deployment of smart grid technology have to be taken in two contexts: the monopoly supplier context and the competitive supplier context. The differences in how smart grid policy would play out in the two models are substantial and merit considerable discussion. The section herein that deals with the role of the incumbent sets out much of the substance, but it is worthwhile to summarize those issues here, and look at the effects of deploying smart grid in competitive and monopoly markets. Indeed, by examining the question of whether the incumbent or an alternative supplier is best suited for deploying smart grid technology at customer premises, we can see what the biases are in both the monopoly and competitive markets. In any event, smart grid policy will evolve differently in those states with monopoly market models than it will in states which allow retail competition, so both models deserve a look.

### MONOPOLY MODEL

The electric utility industry is, by design, risk adverse. Its profits are capped by regulators, so in order to attract the required level of investment at reasonable cost, the industry strives to minimize the risks it faces. In short, its appetite for risk is symmetrical with its limited potential for profit. That applies to technology risks, competitive threats, financial dealings and a variety of other activities. While there have been exceptions to this paradigm (many of them with unhappy results), in general both policymakers and executives have accepted and lived within

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<sup>28</sup> Examples of a federal role on the margins would include the availability of federal funds for installation of smart grid devices, PURPA provisions that called for state regulators to undertake certain activities, the spillover effect of federal policies in regard to wholesale markets, and tax incentives for utilities and/or customers to engage in certain actions.

it for generations. Thus the introduction of new risks, technological or otherwise, has not quickly borne fruit in the industry without some external risk mitigation. In specific regard to technology, that mitigation may come from one of two places. The first is experiential, namely proof of an asset's physical and economic viability (including the likelihood of full cost recovery over the expected life of the asset). This assures that the utility deploying the asset is not the "guinea pig," but rather is investing in equipment in which it has a high degree of confidence based on observing its use elsewhere. The second form of mitigation involves some form of risk sharing. In some cases risks are shared with a vendor. In most cases, however, risk mitigation comes from socializing risks through government grants or guarantees, or, more commonly, through simply passing on costs to customers.

While by law regulated utilities are entitled to pass along all prudently incurred expenses through rates, when taking on additional risks such as deploying new technology, utilities will seek pre-approval of their regulators, which virtually guarantees cost recovery, absent subsequent imprudence of some sort. Additionally, utilities may also seek accelerated recovery where they fear that the physical life of an asset exceeds its technological usefulness. That is precisely what is occurring in regard to smart meters in many jurisdictions in the United States. Indeed, even where utilities have been recipients of government grants to install smart grid meters or other technology, they often seek to cover further installations through pre-approvals from regulators.<sup>29</sup> Accelerated recovery might also be used to offset, or compensate for, the costs associated with undepreciated value of the assets being replaced before their physical obsolescence. In effect, utilities are asking that their regulators make (or bless) their technology decisions, even though the regulators have no particular expertise in doing so<sup>30</sup> and will never be called upon to manage and maintain those assets. Indeed, absent readily observable problems that might lead to a prudence<sup>31</sup> review, the utilities with regulatory pre-approval will be managing assets for which they are not at risk, creating an asymmetrical situation where those responsible for management are at little financial risk, while those who take the financial risk, namely the consumers, have little or no control of the asset.

There are also economic issues regarding the use of the monopoly model in the deployment of smart grid technology. The first is that, to the extent that the technology is used to set up microgrids, utilities are likely to see competitive threats that they would strongly prefer to avert. Even where proposed microgrids are not meant to be competitive but rather to be merely supplemental to the utility to add an additional level power quality, local utilities are still likely to see a competitive threat to be avoided, unless of course they retain full control. That could have the effect of limiting the full scope of smart grid benefits otherwise available to customers. A second economic issue is discussed in some detail in the section of this paper that deals with the role of the incumbent, and requires little more than mention here. Namely, if the utility's ratemaking incentives do not encourage more efficient use of energy and more effective load management, customers in monopoly environments are likely to see less of the demand-side and reliability enhancing benefits afforded by smart meters and control mechanisms. Thus, having utilities deploy smart grid without realigning their tariff incentives runs the very real risk of failing to capture many of the demand-side benefits of deploying the technology.

While there are problems associated with deploying smart grid assets in monopoly markets, it should be noted that there are some advantages in doing so. The first, of course, is that there are substantial supply-side benefits from the deployment of smart grid. Those benefits are substantial and include automated meter reading, connections and disconnections, enhanced reliability and service quality, increased energy efficiency, O&M savings and reduced capital expenditures for system expansion. Those types of supply-side efficiency gains are an inherent part of the incentives provided to monopoly utilities, so monopolies are likely to be focused on capturing them. Some aspects of demand-side benefits, such as peak shaving, are also likely to be appealing to

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<sup>29</sup> An excellent example of seeking pre-approval and accelerated recovery (coupled with substantial federal government grants) is found in Case 9208, In the Matter of the Application of Baltimore Gas and Electric Company for Authorization to Deploy a Smart Grid Initiative and to Establish A Surcharge for the Recovery of Cost., Maryland Public Service Commission., Order No. 83410. While one may agree or disagree with the Commission's decision in the matter, discussion of the issue of pre-approval and allocation of risks in the deployment of smart grid technology provides good insight.

<sup>30</sup> There is always the debate about who should make technology decisions, the market or the state (in this case the regulators or government officials awarding grants). Where the markets drive the decisions, of course, the financial consequences of poor decisions are borne by those making them, a rather symmetrical arrangement. Where regulators or other officials of the state make decisions, including where regulators merely ratify recommendations of utility managers, of course the risks of poor decision making are borne by the tax-paying and/or rate-paying public. While one could argue, often but not always correctly, that the public will be the beneficiary of good decisions, and therefore there is symmetry, that does not address the difficulties associated with separating the decision to invest in a particular technology and the responsibility for actually managing it.

<sup>31</sup> Prudence is defined as a filter that regulators impose in deciding what costs get passed on to consumer. This filter is used to make certain that the only costs that are recovered are those that are reasonably required to provide consumer with the requisite quality of service.

monopolies.<sup>32</sup> Monopoly environments, of course, are more suited to top-down directives than are competitive markets. Thus, legislators and regulators can direct and/or effectuate incentives that compel or make attractive the deployment of desired technology. While that runs the risk the policymakers'/regulators' directives are wrongheaded, it does—in the case of compelling circumstances—avoid having to wait for demand to materialize or having to wait for clever entrepreneurs who are capable of stimulating consumer interest. Such a top-down approach has serious drawbacks in terms of gaining commitments from utilities and consumers alike, but it is nonetheless capable of getting assets deployed.<sup>33</sup>

Another one possible benefit that monopolies might possess is economies of scale in installing and maintaining smart grid technology. In addition, by virtue of the volume of a monopoly's purchase, it has substantial buying power. Both of these factors might enable monopolies to drive down equipment prices—and therefore—costs to customers. How much of a benefit that is, of course, depends greatly on the size and scale of alternative suppliers offering smart grid-related products and services. Finally, as noted, properly incentivized with rates that de-link profits and sales, monopolies can become effective in capturing demand-side benefits as well.

## COMPETITIVE MODEL

In the retail markets that are open to competition, of course, there is an alternative to having the utilities deploy smart grid technology, at least in regard to microgrids and to customer premises equipment, including meters. That alternative is the energy service provider (or load aggregator). The benefit of this alternative is that the energy service provider, perhaps in collaboration with the customer, chooses what technology to deploy and assumes all risks associated with it. Thus, unlike a utility whose cost recovery is assured if it obtains regulatory pre-approval, the energy service provider has a powerful incentive to both select and manage its risks well. For the most part, service providers in a competitive market, unlike a monopoly utility, lack the ability to simply pass on risks and costs to the public by regulatory action. That, of course, serves to further focus service providers' attention—on making the right decisions. Additionally, if service providers choose to do more than merely market energy, and in RTO markets with demand-side bidding they certainly have an incentive to do more (e.g., become full load aggregators—they also would have real incentives to capture much of the demand-side benefits that come with deployment of smart grid technology.

Alternative providers, by virtue of their business, have an entirely different corporate culture than utilities. Whereas utilities are risk averse, in large part because they are earnings limited, alternative providers are willing to take greater risks because their upside potential is greater. In short, they are more entrepreneurial in nature. This can be analogous to the development of telecommunications in the 1980s. At that time, traditional telephone utilities were either unable or unwilling to make investments in new technologies with a significantly shorter useful life than physical life. Those new technologies went on to revolutionize the industry. Leadership, at least for a time, passed to new entrants who were better positioned to take such risks.<sup>34</sup> The same may apply to alternative providers who are better positioned to take the risks associated with smart grid investments.

Entrepreneurial companies, unlike the risk-averse utilities, are all about taking on and managing risk, including technological risk. They may be, at least in a corporate culture sense, much better equipped not only to take on the risks, but also, for competitive reasons, more likely to change outdated technology than wait for assets to fully depreciate. Unlike utilities, entrepreneurial companies can internalize such risks into their pricing. In fact, the business model of non-utility service providers in electricity contains the very symmetry that is lacking in utilities. Those who take on risk stand to benefit or lose from their decisions, and those who select technology are obligated to select and manage it well, because the consequences, good or bad, are theirs to bear. Finally, non-utility service providers that install meters and other smart grid technology are far more likely than utilities to

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<sup>32</sup> Note the section of this paper on Florida, where monopoly utilities have been deploying load management devices in an effort to reduce peak demand.

<sup>33</sup> The problems associated with a "top-down" approach can, of course, be mitigated considerably through attractive pricing that appeals to consumers. This puts the burden on the utility and its regulators to devise such schemes.

<sup>34</sup> There is an irony worth noting in regard to the new technology in telecommunications. Many, although certainly not all, of the technologies that changed the face of the industry were developed by Bell Labs, a subsidiary of the Ma Bell monopoly. Thus, the monopoly developed some of the new technology, but for a variety of reasons never fully deployed or captured the full benefits of it. In some ways, Bell Labs, which could be described as a "public benefits" program of a monopoly, came to symbolize the best and worst aspects of having a monopoly. Bell Labs had the resources to conduct basic and important research, but at the same time was constrained from capturing many of the benefits of the good work it did.

provide benefits to customers such as microgrids and other innovations, because they will be looking for niches to exploit that might not otherwise be filled.

As in the case of utilities, there are downsides to the service providers taking primary responsibility for smart grid. The first and most obvious is that they are not as well positioned as the incumbent utility to capture the supply-side benefits. A second and significant disadvantage is that unlike in the case of utilities, independent service providers are free to exit the market, circumstance that could cause difficulties for customers in continuing to use the meter and other smart equipment on the premises. Additionally, unlike utilities, which can be ordered to deploy technology and/or develop programs, independent service providers are not usually subject to such fiat. From a public policy perspective, independents can ignore government policies and regulations, while utilities have no choice but to follow them. In short, independent service providers are more likely to follow the market, while utilities will be more sensitive to regulators.

Finally, there is a question in competitive markets as to whether it makes sense to link the costs of smart meters to the variable cost of energy or the fixed costs of delivering energy. In a competitive market, the distribution company could provide the smart meters and other customer premises equipment, as well as the service provider. In fact, that is the case currently in most retail competition jurisdictions in the United States. It is not clear, however, that it makes economic logic to link the cost of the meter and other equipment on customer premises to the fixed costs associated with the delivery of energy rather than the variable cost of the energy itself. In fact, one could develop a powerful argument that, where practiced, bidding in demand reduction is greatly facilitated by the use of meter and other customer premises smart grid technology. Thus the technology is more linked to the variable cost of energy than to the fixed cost of delivery.

## RECOMMENDATIONS

### Pricing

There are two critical aspects of pricing: the signals to the customer and the signals to the providers. Achieving the demand-side benefits attainable from deploying smart grid technology is largely, if not totally, dependent upon getting the prices right.

For customers, prices must reflect real-time energy prices and must be conveyed on an actionable basis. This can be accomplished either through real-time conveyance of price information or through agreed-upon central controls of use of energy on the customers' premises. Agreement on central control of appliances would include the appropriate price reductions for the customer reflecting his willingness to suspend consumption under established protocols. Such agreement would also reflect incentives for appropriate peak shaving and time shifting of load.

For providers, both utilities and alternative suppliers, the pricing in the market should offer opportunities for earning that are one-dimensionally linked to sales of energy. For utilities, be they load-serving entities or not, profits ought to be linked to provided energy service, not simply kWh sales. Alternative suppliers in open retail access markets should be provided appropriate wholesale market prices that permit them to serve as both energy suppliers and load aggregators. That way they have an incentive to provide customers with energy on the most efficient basis rather than merely providing energy to be consumed.

There has been push back on real-time pricing from some who prefer to retain current pricing arrangements. Some of this push back stems from fears that real-time pricing will raise prices and that residential and other small customers will expend much effort trying to save small amounts of money. This push back cannot be ignored but must be addressed to allow for both optimal system efficiency and for customers to be empowered to make informed electricity consumption choices.

It is important, therefore, that switching to real-time pricing be done on a phased-in basis so that: (1) customers can learn to navigate it (assuming they wish to achieve the efficiency gains and price breaks offered); (2) customers are offered the alternative of surrendering some control of load to an aggregator or load dispatcher of some sort; and (3) implementation be accompanied by a massive effort to fully educate customers.

There is an alternative between maintaining the status quo and moving all customers to real-time pricing, although it is not ideal. The alternative is requiring the switch to be made first by customers whose load characteristics make them most likely to benefit from real-time pricing and smart meters. The customer may be, for example, a residential customer with a plug-in hybrid automobile. This selective phase-in approach might allow some benefits to be captured while offering change-resistant customers some solace. However, there would not be much of a gain from an economic efficiency standpoint. Thus, while it is not recommended, it is a political fall-back position.

### **Cost Recovery for Smart Grid Investments**

The consideration of how to allow for recovering the costs of smart grid investment should be driven by thinking through such issues as risk allocation, risk management, appropriate incentives and identifying beneficiaries. Based on those considerations, it is recommended that costs associated with smart grid investments before the meter should be recovered as fixed costs. The costs of the meter, customer premises equipment and beyond ought to be recovered on a variable cost (perhaps energy cost) basis. The rationale for this recommendation on the supply-side is that most of the benefits from smart grid investments on the supply-side are systemic, rather than customer specific in nature. Those supply-side benefits relate to service quality, administrative functioning, maintenance and other activities for which it is virtually impossible to identify specific beneficiaries. The value of those activities is not necessarily related to the consumption of energy. Moreover, they have natural monopoly characteristics that customer premises equipment, including the meter, do not.

Customer premises equipment is, by definition, beneficiary specific. The value of it is directly linked to energy consumption or savings. Also, this value is not inextricably linked to the monopoly, since the meters and equipment can be provided and maintained by any supplier. In fact, making the costs of such equipment recoverable as part of the variable charge allows them to be detached from the monopoly utility and opened to competitive providers, should policymakers so decide. Finally, allowing recovery on a variable cost basis would enable more technological innovation and adaptation, as well as more customer exercise of discretion, and enable customers to better control their costs and decide whether to avail themselves to new programs and services.

In this context, it is also recommended that policymakers revisit the issue of who owns and controls the meter, particularly in states with retail competition. For the most part, the decisions to assign responsibility for metering to utilities were made in the static context of “dumb” meters that merely kept track of consumption. In the smart grid context, meters post real-time prices and communicate with appliances, suppliers and the wires' delivery system. Meter ownership is also worth revisiting in the context of different approaches toward managing technology and associated risks by utilities and alternative suppliers (discussed above).

### **Risk Allocation Regarding Smart Grid Deployment**

The risks associated with the deployment of smart grid assets should be allocated on a symmetrical basis on three dimensions. First, risk should be allocated in a way that is symmetrical to the gains to be derived. Thus, low risk should mean less potential for gain, while high risk should have a greater potential for gain. Second, a balance must be struck between the socialization and privatization of risk. It is not sustainable to privatize gains while socializing risk. Conversely, it is not sustainable to privatize risks and socialize gains. The third dimension, closely related to the second, is that risks should be borne by the party in the best position to manage them. Investors in technology are the parties best positioned to control outcomes. They should stand to gain where assets are well managed and should shoulder the risk of loss for poorly managed assets. Passing on costs to customers by regulatory rather than market mechanisms on a “guaranteed” rather than “earned” cost recovery basis is ill advised. Guaranteed cost recovery places risk on customers, who are less well positioned to control outcomes. It also provides the investor with little incentive to manage well and to exercise appropriate business prudence.

In a monopoly setting, regulators may need to replicate the symmetry found in unregulated markets. For example, regulators in a monopoly setting may come to believe that a particular technology investment is high risk. The subject regulated utility may be unwilling to make the investment under their existing rate of return. In that case,

regulators might consider differentiating the rate of return for those investments from that permitted for other types of assets. In that way, the risk reward symmetry is established while continuing to place the burden of management risk on the party best positioned to manage it.

### **Ownership of and Access to Data**

All customer-specific data belongs to the customer, who should have absolute and sole right to it and to disclose or not disclose it as he or she sees fit. Aggregate system data, however, absent some very compelling circumstances, should be considered public information, which should be readily available to all who might seek to use it.

Access to information is critical for electricity markets to work efficiently. In competitive markets, information symmetry for competitors is almost as essential to maintain the requisite equilibrium for the market to function. As well, consumers have a right to expect customer-specific data be treated as confidential and private. Balancing between those two objectives—protecting privacy and maintaining equitable access to data for all competitors—is where public policy needs to be.

Fortunately, there is a readily available policy option that successfully balances these somewhat conflicting objectives. The recommended policy is that all customer-specific information belongs exclusively to the customer. It should not be used by any other party in possession of that information for any purpose not expressly consented to by the customer. Nor can that information be withheld from either the customer or any party to whom the customer wants it to be provided. Under such policy parameters, no competitor can use or withhold the data for his own commercial advantage. Similarly no customer can be deprived of the opportunity to use the data for his own advantage. System information that is not customer specific, absent some compelling circumstances, should be readily available to all who desire to see it. Thus no market participants could be denied symmetrical access to data possessed by other competitors in the marketplace.

### **Universal Installation of Smart Meters**

Ultimately smart meters should be installed on a universal basis. There has been some push back on universal installation because small consumers are likely to get less benefit due to their lower consumption, relatively inelastic demand and—often—flat load curves. The problem with conceding that objection, however, is that allowing some customers to retain “dumb” meters will forego many of the benefits of new technology. Unless all customers are using smart meters, supply or system-wide (supply-side) benefits, such as meter reading, early identification of service problems, enhanced reliability and ease of connection and disconnection, will be partially lost. Some of the scale economies associated with switching out all “dumb” meters will also be lost. It should be noted, however, that if the meter costs were variable rather than fixed costs, as recommended above, small customers would pay a lesser share of the costs than they do at present. Once the meters are installed, of course, both utilities and entrepreneurial third parties can offer customers services that smart meters enable.

### **Guidelines and Standards**

The National Institute of Standards and Technology (NIST) is working to develop standards for smart grid technology and equipment. While this paper does not intend to list all the subjects on which there ought to be standards, there are two areas regarding meters and data systems that do require specific mention.

The first is that smart meters should be able to communicate with both customer premises equipment and the local utility. This ensures that specific meter choices do not automatically preclude the achievement of both supply and demand benefits. Meters also ought to be transferable from one supplier to another, if the customer in a retail competition jurisdiction chooses to switch suppliers. While further technological development may well be required to achieve these objectives, it is critical that meters serve as instruments of customer enablement and not be used to limit a customer's discretion.

The second standard is that there be stringent requirements for smart meters and data collection systems to protect the privacy to which consumers are entitled. Individual customer data should not be accessible to outside parties, and system standards ought to reflect that objective.

### **Specifically Enumerated Customer Empowerment**

Smart grid is only as valuable as what it enables customers to do. Accordingly, it is recommended that laws or regulations explicitly state what customers are entitled to if they are obliged to pay for the installation of the enabling technology. The elements of empowerment should, at a minimum, include the following:

1. Right to confidential treatment of customer specific data;
2. Right to customer ownership of, and control of access to, near real-time information and data specific to him/her;
3. Right to a portfolio of supply options (e.g., green portfolio) in monopoly markets and unfettered consumer choice in open retail markets;
4. Right to receive real-time price information on a timely basis that enables response;
5. Right to choose to have central dispatch of customer premises equipment (e.g., appliance control) subject to agreed-upon protocols with appropriate pricing;
6. Right to install equipment, either individually or collectively, with other customers, to improve electric service quality (e.g., microgrids) as long as the installation has no adverse effects on the rest of the system;
7. Right to have net metering and dynamic market pricing for distributed generation;
8. Right to subscribe to aggregation of demand for purposes of demand-side bidding;
9. Right to select his/her meter and post-meter devices, as long as they are in conformity with applicable standards;
10. Right to avoid exposure to asymmetrical allocation of risk and reward associated with the installation of smart grid assets; and
11. Right to choose and invest in the desired level of power quality.

### **Evaluation of Smart Grid Related Programs**

As with the introduction of any new products or programs into a regulated market, there should be close monitoring of how assets are being deployed and what benefits are being derived or not derived. The purpose of such close monitoring is twofold: (1) to learn lessons both good and bad, quickly; and (2) to cut losses for consumers where something has gone very wrong by either making mid-course corrections or where appropriate, simply curtailing failing programs. It is critical that regulators and market participants be positioned to learn appropriate lessons to fully capture and retain the value of smart assets.

It would also be very useful to look at different types of demand response programs enabled by smart meters and related equipment. This could shed light on what approaches achieve the best results. Also useful would be an assessment of the results in demand programs that are enabled by timely price disclosure, as contrasted with those associated with central dispatch of appliances within the premises of customers.

In conducting such evaluations, however, it is important to keep in mind that the criteria on which programs are evaluated are multidimensional. Price, while certainly not insignificant, cannot be the sole criterion. Other criteria might include the environmental effects of not having to dispatch a “dirty” and inefficient marginal generator, reduced need to use social subsidies because of efficiency gains, better utilization of time constrained renewable resources (e.g., wind), and a variety of other non-price-related criteria.

## 4. State Analysis: California

Among the states surveyed, California has the nation's most active smart grid state law and regulation. Historically, the state has been the nation's largest investor in energy efficiency. California has also aggressively sought federal smart grid funding and has addressed both EISA and ARRA recommendations. As discussed below, California's smart grid policy has been driven by its smart grid-specific statute—the nation's first, which statute characterizes California's smart grid, echoing federal definitions. Importantly, one characteristic of the statute is that unreasonable or unnecessary barriers to adoption of the smart grid must be identified and lowered. California has long embraced advanced metering and concurrently implemented advanced pricing models (often by mandate). After suspending restructuring, California recently signaled that it will open more customers up to retail competition.

California achieved a great deal of notoriety for the failure of its competitive market design, which was implemented in the late 1990s. The well-known failures of that market design, which was approved by both the California legislature and the FERC, are notorious and do not need repeating here. The California experience had a substantial political impact in that it considerably slowed the move toward restructuring. Many policymakers, rather than drawing the conclusion that the market design was bad, instead concluded that restructuring was problematic. This political impact, however, was probably out of proportion due to the specific problem associated with the California market design, since successful restructuring has occurred in other markets across the country.

### UPDATE ON CALIFORNIA RETAIL MARKET

Restructuring and retail choice was suspended in California in October 2001. On March 11, 2010, the California Public Utilities Commission (CPUC) announced a plan to increase the number of "direct access" transactions for nonresidential customers within the service territories of California's major investor-owned electric utilities.<sup>35</sup>

Direct success in California allows eligible customers to purchase electricity from an independent electric service Provider rather than from investor-owned utilities (IOUs). It was first instituted in 1998 and currently represents about 5 percent of total retail sales across the state are direct access transactions.

Effective April 11, 2010, all qualifying nonresidential customers will be eligible to take direct access service up to specified maximum annual caps that will be phased in over a four-year period. The phase-in will be conducted as follows: 35 percent of total allowable direct access sales will be allowable in year one; 35 percent in year two; 20 percent in year three; and 10 percent in year four. The four-year phase-in period will result in approximately 11 percent of total retail sales being served by entities other than the IOUs (the historical maximum the state reached in 2001).

The caps are intended to limit potential risks by eliminating the uncertainty associated with load migration. The phase-in schedule is intended to provide enough lead time for IOUs to account for small shifts in load, avoiding unwarranted cost shifting and stranded load.

### SMART GRID POLICY IN CALIFORNIA

California has aggressively pursued smart grid policies and federal smart grid funding. In 2003, the CPUC adopted a policy that all electric customers should have advanced meters. Advanced meters are now in place for customers with greater than 200 kW maximum demand. System-wide advanced metering deployments were approved for PG&E, San Diego Gas & Electric (SDG&E) and Southern California Edison (SCE), the three major California utilities. Concurrent tariff changes were made to offer TOU and dynamic pricing. In September of 2009, the CPUC established an expedited review process for smart grid funding. The major California utilities are decoupled.

<sup>35</sup> Press release, CPUC, "CPUC Allows Non-Residential Customers Choice of Electric Provider" (Mar. 11, 2010), [http://docs.cpuc.ca.gov/PUBLISHED/NEWS\\_RELEASE/114809.htm](http://docs.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/114809.htm). The plan is being implemented in accordance with Senate Bill (S.B.) 695.

In October 2009, California passed S.B. 17, endorsing the development of smart grid deployment plans. S.B. 17 is one of the first, if not the first, state bills specific to the development of a smart grid, and it characterizes the California smart grid.<sup>36</sup>

S.B. 17 requires that the CPUC, by July 2010 and in consultation with the State Energy Resources Conservation and Development Commission, the California Independent System Operator (CAISO), and other key stakeholders, determine the requirements for a smart grid deployment plan consistent with the policies set forth in the bill and federal law. It also requires that the smart grid improve overall efficiency, reliability and cost-effectiveness of electrical system operations, planning and maintenance. All utilities with more than 100,000 service connections are required to submit a smart grid deployment plan to the CPUC by July 1, 2011. The plans are authorized to provide for deployment of smart grid products, technologies and services by nonutilities. Smart grid technologies are to be deployed in an incremental manner to maximize the benefit to ratepayers and to achieve the benefits of smart grid technology. The CPUC is also required to report, by January 1, 2011, and then each year after, to the governor and to the legislature and recommend smart grid plans and deployment.

## RECENT DEVELOPMENTS IN PRIVACY CONSUMER PROTECTION

Throughout 2009, the CPUC held workshops on smart grid implementation issues, including consumer, privacy and technical issues, affecting the electric transmission network and energy storage in California.

In December 2009, the CPUC adopted policies and findings pursuant to smart grid policies established by EISA.<sup>37</sup> In the *CA EISA Adoption*, the CPUC also adopted policies for SCE, PG&E and SDG&E concerning consumer access to usage and price information. The three utilities were required to provide consumers and third parties approved by consumers with collected usage data by the end of 2010. The utilities were also required to provide those customers with smart meters and to allow access of usage data to authorized third parties on a near real-time basis by the end of 2011.

In the *CA EISA Adoption*, the CPUC determined that its current ratemaking procedures, which offer IOUs a reasonable return on investments made to provide service to ratepayers, were sufficient to apply to smart grid investments. The CPUC stated that “special rate treatment for smart grid investments would likely prove counterproductive and lead to regulatory delays.”<sup>38</sup> The CPUC also stated that “granting premiums above market may, absent a compelling reason, distort investment and lead to inefficient results.”<sup>39</sup> The CPUC also decided to defer consideration of specific rate treatment for obsolete equipment to general rate cases or applications that address smart grid investments.<sup>40</sup>

In February of 2010, the CPUC issued an administrative law judge and assigned commissioner joint ruling requesting that parties submit comments pertaining to proposed policies and findings concerning the smart grid, including policies to implement S.B. 17’s proposed metrics and proposed access rules.<sup>41</sup>

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<sup>36</sup> The California smart grid includes: (a) increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid; (b) dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cybersecurity; (c) deployment and integration of cost-effective distributed resources and generation, including renewable resources; (d) development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources; (e) deployment of cost-effective smart technologies, including real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation; (f) integration of cost-effective smart appliances and consumer devices; (g) deployment and integration of cost-effective advanced electricity storage and peakshaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning; (h) provision to consumers of timely information and control options; (i) development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid; and (j) identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.

<sup>37</sup> Decision Adopting Policies and Findings Pursuant to the Smart Grid Policies Established by the Energy Information and Security Act of 2007, CPUC, Decision No. 09-12-046 (Dec. 17, 2009) (the “CA EISA Adoption”).

<sup>38</sup> CA EISA Adoption at p. 35.

<sup>39</sup> Id.

<sup>40</sup> CA EISA Adoption at p. 39.

<sup>41</sup> Assigned Commissioner and Administrative Law Judge’s Joint Ruling Amending Scoping a Memo and Inviting Comments on Proposed Policies and Findings Pertaining to the Smart Grid, CPUC (Feb. 8, 2010) (the “CPUC 2010 Joint Ruling”).

Also in the *CPUC 2010 Joint Ruling*, the CPUC proposed alternative uses for the utility deployment plans mandated by S.B. 17, and expressed preference for approved plans to be: (1) a baseline for the CPUC to monitor a utility's deployment of smart grid technologies and capabilities; and (2) used by a utility or other party to explain reasonableness of specific investments. The CPUC did not favor the use of plans that convey a presumption of reasonableness of future investments.<sup>42</sup>

In the *CPUC 2010 Joint Ruling*, the CPUC proposed rules regarding customer information. The proposed rules state that an electrical corporation should provide to a customer, the customer's electric service provider, the customer's demand response provider or other third-party entity authorized by the customer, read-only access to the customer's advanced meter data. This includes meter data used to calculate charges for electric service, historical load data and any other proprietary customer information.

In addition, the proposed rules state that utilities must have written authorization from the customer to release usage data to the requiring party only. This written authority may be broadened at the customer's request. Subject to customer authority, a utility will: (1) provide the most recent 12 months of customer usage data (in a format consistent with industry standards) as approved by the CPUC; and (2) make available a database containing a 12-month history of customer-specific usage information (with customer identities removed). The draft rules state that by authorizing a third party to access information, the customer consents to release to that third party the information required for billing, settlement and other functions and services required for that entity to meet its requirements and obligations, in addition to 12 months of historical data. Such authorization may be made in writing or via electronic signature, consistent with industry, privacy and security standards and methods.

## INCENTIVES

The CPUC established an incentive mechanism to encourage IOUs to promote energy efficiency and to meet the CPUC's energy savings goals. The CPUC has awarded PG&E incentive revenues totaling \$75 million through December 31, 2009, based on the energy savings achieved during the 2006–2008 program cycle.

California's programs supported by a ratepayer surcharge are robust. The CPUC implemented 215 programs during the 2006–2008 period related to energy efficiency and conservation that were supported by California's ratepayers through a surcharge. For 2006–2008, the programs had a budget of \$2.2 billion and produced projected energy savings of 1685 MW and 7367 GWh. They also avoided construction of two 500 MW power plants between 2004 and 2007. California's IOUs have approval for approximately \$3.1 billion in energy efficiency programs for 2010–2012 that have a projected savings of almost 7,000 GWh of electricity and that avoid the construction of three 500 MW power plants.<sup>43</sup>

## RECENT DEVELOPMENTS IN RATES

On February 25, 2010, the CPUC adopted new rate structures for commercial, industrial and agricultural customers of PG&E to implement dynamic electricity prices.<sup>44</sup> Rates are designed to reflect the cost of electricity production during periods of high demand.

Many commercial and industrial customers will begin moving to new peak-day-pricing rates by November 2011 and will pay different prices for electricity depending on the time of day. There are options built in for customers to reduce uncertainty caused by the new rates. For example, customers can have the option to protect themselves if their first year's costs exceed those under the old rate structure. Customers can also opt out of the peak-day-pricing rate any time within the first year of participation.

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<sup>42</sup> *CPUC 2010 Joint Ruling* at p. 6.

<sup>43</sup> *California's Long-Term Energy Efficiency Strategic Plan Fact Sheet*, CPUC (Sep. 24, 2009), available at <http://www.californiaenergyefficiency.com/docs/EEFactSheet092409.pdf>.

<sup>44</sup> Application of Pacific Gas and Electric Company for Approval of its 2009 Rate Design Window Proposals for Dynamic Pricing and Recovery of Incremental Expenditures Required for Implementation, "Decision on Peak day pricing Peak day pricing for PG&E," Application No. 09-02-022, CPUC (Mar. 13, 2009).

The CPUC ordered PG&E to conduct outreach and education activities and take measures to ensure that customers are aware of and understand the new rates and options. The decision states that:

- Large commercial and industrial customers were defaulted to peak-day-pricing rates on May 1, 2010, unless they proactively choose to opt out to a time-of-use rate. Peak-day-pricing will become the default tariff for small and medium commercial and industrial customers beginning November 1, 2011.
- Peak-day-pricing will become the default tariff for large agricultural customers beginning February 1, 2011. Time-of-use rates will become the default tariff for small agricultural customers beginning February 1, 2011.
- There will be between nine and 15 peak-day pricing event days per calendar year.
- All customers that are defaulted to or choose peak-day-pricing rates will be afforded bill stabilization for the first year unless they choose to waive such protection. All customers subject to peak-day pricing will have a hedging option to reduce bill volatility.
- Customers who are on peak-day pricing rates may opt out any time during the first year they are on such rates.

It should be noted that on March 8, 2010, the California Public Utilities Commission (CPUC) announced that it expects to announce an independent evaluator to investigate PG&E's smart meter program.<sup>45</sup> This is due to customer complaints of skyrocketing electric bills after smart meters were installed in their homes, leading to some concerns that the meters were malfunctioning or intentionally overcharging.<sup>46</sup>

## DISTRIBUTED GENERATION

The CPUC regulates incentives and programs for distributed generation. Customer side of the meter distributed generation incentive programs include the California Solar Initiative and the Self-Generation Incentive Program. California's net metering and interconnection policies support these programs. Utilities procure distributed generation resources through a variety of procurement programs that include competitive solicitations, feed-in tariffs, utility solar programs and small combined heat and power tariffs.

To determine the costs and benefits of distributed generation projects, the CPUC utilizes the participant test, the total resource cost test (including its variant, the societal test) and the program administrator cost test.<sup>47</sup>

California began allowing communities to aggregate load and buy power from competitive suppliers rather than utilities in 2002. On April 30, 2007, the CPUC authorized its first Community Choice Aggregation application.

In 2010, PG&E placed a measure on the June 2010 California statewide ballot that would require communities to get the backing of two-thirds of the voters in the area in order to aggregate. California state lawmakers were critical of PG&E's actions, with some questioning whether or not ratepayer money was being used to defeat community aggregation. The ballot measure failed.

California has a state standby rates policy. Standby rates must: (1) provide for fair cost allocation among customers; (2) allow the utility adequate cost recovery while minimizing costs to customers; (3) facilitate customer-side distributed generation deployment; and (4) send proper price signals to prospective purchasers of distributed generation.<sup>48</sup>

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<sup>45</sup> Mercury News Online (Mar. 9, 2010), [http://www.mercurynews.com/business/ci\\_14634754?source=rss](http://www.mercurynews.com/business/ci_14634754?source=rss) (the "Mercury Article").

<sup>46</sup> Mercury News. *Ibid.*

<sup>47</sup> Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues, CPUC, Decision No. 09-08-026 (Aug. 20, 2009).

<sup>48</sup> Order Instituting Rulemaking into Distributed Generation, CPUC, Decision No. 01-07-027 (Jul. 12, 2001).

## CAISO AND DEMAND RESPONSE PROGRAMS

CAISO allows for participating loads (real time CAISO curtailable loads) to directly participate in the ISO non-spinning reserves, replacement reserves, and supplemental energy markets. CAISO relies on an estimated 1,500 MW of capacity resources administered by the California's IOUs augmented by price-responsive program enrollments.

CAISO's utility-managed price responsive programs include critical peak pricing retail tariffs in which program participants are charged significantly higher rates for peak hours of declared critical peak days. They also include various price-based programs in which customers are paid to reduce consumption when certain market conditions are triggered.

## 5. State Analysis: Colorado

Colorado is the home of important smart grid projects and is actively grappling with smart grid issues. Colorado has not been addressing smart grid deployment through smart grid-specific legislation or mandates. The COPUC, however, has been open to addressing smart grid issues and has shown a willingness to evaluate and potentially modify its rules. Colorado is an example of a state where AMI is moving forward and issues have been addressed as they have arisen.

### RETAIL MARKET OVERVIEW

Colorado is not a restructured state. The COPUC investigated restructuring in 1996 and 1999, a majority of the Colorado Electricity Advisory Panel voted against restructuring the industry, citing Colorado's low rates and projections that restructuring would raise rates disproportionately among customer classes.

### RECENT ENERGY-RELATED LEGISLATION

In 2007, the Colorado General Assembly passed, and the Governor signed, House Bill (H.B.) 07-1037. The new law established minimum energy efficiency targets and empowered the COPUC to bring about substantial and effective demand-side management (DSM) programs. As of 2009, all Colorado IOUs have approved DSM plans in place.

H.B. 07-1228 was signed into law on June 1, 2007, charging the COPUC to: (1) develop policy to establish incentives for consumers who produce distributed generation; and (2) consider whether a credit program similar to Colorado's renewable energy credit program would work for consumers who produce distributed generation. In June 2007, the COPUC opened a docket to develop policy as required by H.B. 07-1228.

Also in 2007, H.B. 07-1150 created a Colorado Clean Energy Development Authority, which is tasked with facilitating the production and consumption of clean energy and increasing the use of transmission and of clean energy.

### TIME-BASED RATES

In March 2008, the COPUC decided not to adopt EPA's PURPA Standard 14 related to time-based metering and communications. This was, in part, based on the fact that Public Service and parent Xcel Energy were building the smart grid city demonstration project in Boulder, Colo., and that Aquila Networks intended to deploy AMI in the City of Pueblo.

On March 3, 2010, the COPUC approved block rates for Xcel Energy. Under the new tiered rates, residential customers with average usage will pay about 2 percent more in summer and about 5 percent less during the remainder of the year.

### PRIVACY AND CUSTOMER INFORMATION

The COPUC has an ongoing proceeding that is investigating privacy concerns and smart grid development. On March 2, 2010, the COPUC released an order detailing specific privacy issues for investigation. These issues include: (1) Does the COPUC rule prohibiting disclosure of customer information to third parties absent customer consent need to be modified? (2) Does the COPUC rule regarding customer disclosure need modification given an increase in data from smart technology? (3) Does the COPUC rule requiring customer authorization for each request need to be modified? (4) Should the rules be amended to state that a utility is required to hold its contractors to the same customer data protection standards to which the utility is subject? (5) What amount of data requests from customers should utilities reasonably accommodate and how would the costs be recovered? (6) Do current rules allowing utility disclosure to government agencies adequately further the objectives of government-authorized energy programs like those promoting energy efficiency? (7) Is there a definable minimum level of customer-specific information that can be disclosed to third parties without requiring customer consent?

(7) To what standard should utilities and their agents be held regarding safeguarding electronic data? and  
(8) What type of state or federal statutes govern the treatment of electronic data anticipated by the deployment of smart metering technology?

It is worth noting that, in the case of the COPUC's investigation into privacy, a specific report was particularly influential. In 2008, Elias Quinn a Colorado law school student prepared a report on Colorado's smart grid and privacy.<sup>49</sup> As part of his outreach for the project, he met with the COPUC to share his conclusions and make recommendations. He later presented his completed paper to the COPUC, which used it as the framing document to open an investigatory docket addressing the privacy consequences of smart grid deployment.<sup>50</sup>

## SMART GRID CITY

On December 24, 2009, the COPUC ordered Public Service to apply for a CPCN for its SmartGridCity project,<sup>51</sup> which was designed to build the "world's first fully functioning smart grid city."<sup>52</sup> In the *Phase I Order*, the COPUC found that the SmartGridCity project did not qualify for exemption from a CPCN because it was not "in the ordinary course of business," nor was it a "simple distribution project" as defined by statute and interpreted by the COPUC.

SmartGridCity was not considered in the ordinary course of business because of: (a) its cost and magnitude (\$42 million); (b) its uniqueness, including the fact that many of the technologies are being deployed for the first time; and (c) elaborate financing and intellectual property arrangements.<sup>53</sup> It was not a simple distribution project, as it incorporates generation elements and did not "neatly" fit into the statutory definition of distribution project. Public Service was therefore required by statute to apply for a CPCN. The COPUC did, however, permit Public Service to begin recovering the costs associated with the project pending the CPCN proceeding and subject to refund if the CPCN application was denied.

Spurred by its investigation into SmartGridCity, on February 24, 2010, the COPUC opened a docket to investigate issues related to the smart grid, including SmartGridCity. The investigation includes the following issues: (1) lessons learned from smart metering implementation activities in Colorado; (2) options for and impediments to full smart grid system deployment; (3) smart grid technology and the existing communications infrastructure; (4) cybersecurity concerns; (5) customer participation in demand-side management; (6) distributed generation; (7) dynamic pricing; (8) customer education; (9) cost recovery; and (10) grid/load management.<sup>54</sup>

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<sup>49</sup> See Elias Leake Quinn, "Smart Metering and Privacy: Existing Law and Competing Policies—A Report for the Colorado Public Utilities Commission" (Spring 2009), available at [http://www.dora.state.co.us/puc/DocketsDecisions/DocketFilings/09I-593EG/09I-593EG\\_Spring2009Report-SmartGridPrivacy.pdf](http://www.dora.state.co.us/puc/DocketsDecisions/DocketFilings/09I-593EG/09I-593EG_Spring2009Report-SmartGridPrivacy.pdf).

<sup>50</sup> See Colorado Law School web site at <http://lawweb.colorado.edu/news/showArticle.jsp?id=545> (last visited Apr. 7, 2010).

<sup>51</sup> *Order Addressing Phase I and ECA Issues*, COPUC, Decision No. C09-1446, (Dec. 24, 2009) (the "*Phase I Order*").

<sup>52</sup> See Timothy Hurst, "World's First Smart Grid Enabled City Goes Live," Earth and Industry Web site (Sep. 10, 2009), available at: <http://earthandindustry.com/2009/09/worlds-first-smart-grid-enabled-city-goes-live> (last visited Apr. 7, 2010).

<sup>53</sup> The *Phase I Order* at p. 59.

<sup>54</sup> See COPUC Docket No. 10I-099EG.

## 6. State Analysis: Connecticut

The state of Connecticut has embraced energy efficiency incentives and decoupling. It has also mandated advanced metering among its major utilities and has addressed DSM issues. Connecticut also has a statewide back-up rates policy and a competitive process for default service.

### RETAIL MARKET OVERVIEW

Connecticut is a restructured state with retail competition. As of August 1, 2009, nearly two hundred thousand, or 13 percent, of Connecticut residential and business customers had chosen an electric supplier.

### RATES AND INCENTIVES

In 2006, the Connecticut Department of Public Utility Control (DPUC) directed Connecticut Light & Power and United Illuminating (CL&P “ and “UI” respectively) to begin a phase-in of mandatory TOU rates for residential and commercial customers. The phase-in, will take place over several years and began with high-use customers in 2008. In each succeeding year, mandatory TOU rates will be applied to additional customers based on declining levels of consumption or demand.

Connecticut has both cost recovery mechanisms and incentives. The Electric System Benefits charge has an annual budget of \$62 million. Electric distribution companies recover lost revenues if earnings fall below their allowed rate of return for six months. The DPUC has introduced a lost-revenue recovery mechanism for new conservation and load management, electric load response and distributed generation initiatives. The DPUC uses the TRC test to evaluate the total benefit of utility programs and to determine performance incentives.

H.B. 7432 directed the DPUC to order decoupling of an electric distribution company’s revenues from the company’s sales. This was to be done through rate design changes a sales adjustment clause or both at the time of the company’s next rate proceeding. Any adjustment to the, company’s authorized return on equity should be made as a result of the decoupling in that rate case.

The 2006 H.B. 7501 established several initiatives to reduce costs associated with congestion on the electric transmission system. It created incentives for customers install distributed resources (small-and medium-size generating facilities and conservation and load management measures) on their premises. The incentives include capital and operating-cost subsidies and the provision of long-term financing. H.B. 7501 also provided awards to electric companies for their efforts in connection with the installation of these resources.

Connecticut utilities have addressed costs associated with peak demand for electricity for several years. As stated by the DPUC, for example, “UI implemented mandatory seasonal rates in 1990, a ratcheted demand rate in 1986 and has offered optional time-of-use rates for over 20 years. As a result, all of UI’s approximately 330,000 customers have been billed under a seasonal rate structure for some time, and about 35,000 residential customers and approximately 12,000 commercial/industrial customers are currently being billed under time-of-use rates.”<sup>55</sup>

H.B. 7501 requires CL&P and UI to submit a plan to the DPUC to deploy an advanced metering system that is capable of tracking hourly consumption to support rates like TOU or real-time pricing. H.B. 7501 further requires that an advanced metering system must support net metering and be capable of tracking hourly consumption to support proactive customer pricing signals through innovative rate design, such as time-of-day or real-time pricing of electric service for all customer classes.

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<sup>55</sup> *Application of the United Illuminating Company to Increase its Rates and Charges*, DPUC, Docket No. 05-06-04 (Aug. 30, 2006) at p. 1.

## CONSUMER PROTECTION CUSTOMER INFORMATION

Connecticut has a code of conduct for electric distribution companies (EDCs) that includes rules protecting customer information, disclosure requirements and competition. There are specific billing requirements for EDCs and electric suppliers. The rules mandate that surcharges and customer service information be listed on customer bills.

An EDC may release a customer's name, address, telephone number and rate class to its generation entities or affiliates without customer consent. Such information must, however, be released on a strictly nondiscriminatory basis. Prior written consent is required before any other types of customer information can be released.

To obtain a license, an EDC must file an application that includes information about its financial health, managerial experience and whether or not it is under investigation by an authority or regulatory body. At the discretion of the department, the scope of any license may be restricted to the provision of service to a geographic area, the provision of service to a particular type of customer, a method of operation (e.g., generator, broker, marketer), or the services it offers (e.g., energy services, backup services). In addition, the scope of a license may be restricted based on the DPUC's assessment of the technical, managerial and financial capability of the applicant and the scope-of-service plan submitted by the applicant.

## BACK-UP RATES

In Connecticut, customers who installed customer-distributed generation after January 1, 2006, are not required to pay back-up power rates as long as their generation is not higher than their peak load and their generation is available during peak periods. Also in Connecticut, competitive bidding is required for the provision of default and back-up generation service.

## 7. State Analysis: Florida

Florida does not have voluminous laws addressing the smart grid by name, but the state has historically enabled policies that have led to a high level of utility AMI. Florida also has advanced DSM policies. As a result, Florida is one of the most aggressive smart grid states in the nation and is the preeminent example of a non-restructured state in which considerable power is vested in the state commission by statute. Perhaps as a result, among the states reviewed, Florida has some of the most detailed and extensive rules on metering, including dispute resolution.

### REGULATION OF RETAIL MARKETS

Florida is not a restructured state and does not have retail competition. Decoupling is not in use in Florida at this time, and the Florida Public Service Commission (FLPSC) recently rejected the use of incentives for demand-side renewable energy systems. The FLPSC is authorized to take such action as is necessary to assure that energy reserves of all utilities in the energy grid be available at all times to ensure that grid reliability and integrity are maintained. The FLPSC also has the power to require any electric utility to transmit electrical energy over its transmission lines from one utility to another or as a part of the total energy supply of the entire grid subject to statutory limitation.

In addition, Florida regulation of the wholesale rates charged by an electric cooperative to its members is well within the scope of “legitimate local public interests” that will be upheld under the Federal Commerce Clause. This is in light of the consideration that although a cooperative may be tied into an interstate grid, its basic operation consists of supplying power from generating facilities located within the state to member cooperatives, all of which are located within the state.<sup>56</sup>

### RATES AND PRICING

The FLPSC is authorized to approve rates, on an experimental or transitional basis, for any public utility to encourage energy conservation or to encourage efficiency. The application of such rates may be for limited geographic areas and for a limited period. Florida utilities may seek to recover costs for energy conservation programs and certain economic development programs. Generally, the FLPSC uses base rates and cost recovery clauses.

Florida utilities have been implementing TOU and dynamic pricing for several years. The FLPSC has stated that “Florida customers enjoy a wide variety of time-responsive rate options” and that Florida “utilities have demonstrated a commitment to customer pricing options for over 25 years.”<sup>57</sup>

In 2008, Florida enacted H.B. 7135, which directed the FLPSC to adopt a Renewable Portfolio Standard for public utilities, required utilities to develop standardized net metering programs for customer-owned renewable energy generation, and directed the Public Service Commission to investigate utility revenue decoupling.

### CUSTOMER INFORMATION AND CONSUMER PROTECTION

Utilities are required to give customers information, as reasonable, so that the customer can secure safe and efficient service. Upon request, the utility must provide any customer information as to the method of reading meters and the derivation of billing therefrom, the billing cycle and the approximate date of monthly meter reading. The utility is also required to provide to the customer a copy and explanation of the utility’s rates and provisions applicable to the type or types of service furnished or to be furnished to said customer and to assist the customer in obtaining the rate schedule that is most advantageous to the customer’s requirements.

<sup>56</sup> *Arkansas Elec. Co-op. Corp. v. Arkansas Public Service Commission*, 461 U.S. 375 (1983) as interpreted by 43 Fla. Jur 2d § 51.

<sup>57</sup> *Order Declining to Adopt PURPA Standard 14, Time-Based Metering and Communications*, FLPSC, Order No. PSC-07-02 12-PAA-EU (Mar. 7, 2007) at p. 4.

In Florida, the Division of Consumer Services of the Department of Agriculture and Consumer Services is responsible for preparing lists of sources for energy conservation products or services and of financial institutions offering energy conservation loans, if such lists are required pursuant to federal law. The lists are prepared for the service area of each utility and provided to the utility for distribution to its customers. The lists are updated systematically, and any person who has shown to exhibit unsatisfactory work is to be removed from the list.

## METERS

The FLPSC rules include several provisions regulating meters that include rules regarding installation, reading, laboratory standards, location and billing. All energy sold to customers shall be measured by commercially acceptable measuring devices owned and maintained by the utility (subject to exception).

There are specifications as to how meters should be read, tagged and set and there are accuracy requirements for each type of meter. Florida utilities are required to submit meter test plans for all types of metering equipment for review. Rules also exist for regulating underbilling and overbilling and for dispute resolution. In the event of unauthorized or fraudulent use or meter tampering, the utility may bill the customer on a reasonable estimate of the energy used.

## DSM

The Florida Energy Efficiency and Conservation Act (FEECA) requires the FLPSC to adopt appropriate goals designed to increase the conservation of expensive resources, such as petroleum fuels) to reduce and control the growth rates of electric consumption and weather-sensitive peak demand. H.B. 7135 amended the Florida rules to state that when such goals are established, the FLPSC is required to: (1) evaluate the full technical potential of all available demand-side and supply-side conservation and efficiency measures, including demand-side renewable energy systems; (2) establish goals to encourage the development of demand-side renewable energy systems; and (3) allow efficiency investments across generation, transmission and distribution, as well as efficiencies within the user base.

H.B. 7135 also authorized the FLPSC to allow investor-owned electric utilities an additional return on equity of up to 50 basis points for exceeding 20 percent of their annual load growth through energy efficiency and conservation measures. The bill may authorize financial penalties for those utilities that fail to meet their goals. In addition, H.B. 7135 provided funds for the FLPSC to obtain professional consulting services if needed.

In March 2008, the FLPSC adopted interconnection rules for renewable energy systems up to two MW in capacity. The FLPSC rules apply only to the state's investor-owned utilities; the rules do not apply to electric cooperatives or municipal utilities.

## ADDITIONAL ENERGY EFFICIENCY INFORMATION

H.B. 7135 explained what the FLPSC must consider when establishing conservation goals. Specifically the FLPSC must take into account the costs and benefits to customers participating in the measure and the costs and benefits to the general body of ratepayers as a whole, including utility incentives and participant.

The FLPSC establishes numeric energy efficiency goals for the utilities subject to FEECA at least every five years.<sup>58</sup> In the *FL 2009 Goals Order*, the FLPSC adopted the "participants test" to measure the costs and benefits to consumers.<sup>59</sup> The FLPSC adopted the rate impact measure (RIM) test and the TRC test to measure the costs and benefits to the general body of ratepayers as a whole.<sup>60</sup>

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<sup>58</sup> In re: Commission Review of Numeric Conservation Goals, FLPSC, Order No. PSC-09-0855-FOF-EG (Dec. 20, 2009) (the "FL Goals Order").

<sup>59</sup> The FL Goals Order at p. 9.

<sup>60</sup> *Id.*

The FLPSC recently directed IOUs to file pilot programs for renewable programs subject to expenditure caps<sup>61</sup> and stated that it was the intent of the Florida legislature to place added emphasis on renewables while protecting ratepayers from undue rate increases by requiring the IOUs to offer renewable programs subject to an expenditure cap.

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<sup>61</sup> In the FL Goals Order at p. 25, the FLPSC stated that “We direct the IOUs to file pilot programs focusing on encouraging solar water heating and solar PV technologies in the DSM program approval proceeding. Expenditures allowed for recovery shall be limited to 10% of the average annual recovery through the Energy Conservation Cost Recovery clause in the previous five years as shown in the table below. Utilities are encouraged to design programs that take advantage of unique cost-saving opportunities, such as combining measures in a single program, or providing interested customers with the option to provide voluntary support.” This was despite the fact that none of the demand-side renewable energy systems were found to be cost-effective in the utilities’ analysis.

## 8. State Analysis: Illinois

Illinois is active in pursuing smart grid strategies, though it has not embraced incentives or decoupling. Illinois has, however, mandated real-time pricing for its large utilities. As described below, its establishment of a statewide collaborative to address smart grid issues was an important development. Illinois is an example of a restructured state that has less mature codes of conduct to support competitive retail markets. The Illinois Commerce Commission (ICC) is, however, investigating ways to enhance these codes.

### RETAIL MARKET OVERVIEW

Illinois law provides for retail competition in residential energy supply services as well as for commercial and industrial customers. The ICC has jurisdiction over certain aspects of competitive electricity marketing.

### “SMART RATE” STRUCTURE, INCENTIVES AND COST RECOVERY

Real-time pricing in Illinois is required by statute for utilities providing service to more than 100,000 customers. The state's two major utilities Commonwealth Edison, (ComEd) and Ameren Utilities) currently offer real-time pricing to consumers. In June 2009, the ICC issued public comment on the results of Ameren Utilities' and ComEd's real-time pricing programs.

The electric utility may apportion the costs of real-time pricing disproportionately to the residential customers who elect it. Some of the costs of real-time pricing, however, may be imposed on customers who do not elect it. This is provided that the ICC determines that the cost savings resulting from real-time pricing will exceed the costs imposed on customers for maintaining the program.

Currently, incentives in Illinois consist primarily of small-scale electric energy programs supported by assessments on electric utilities. The Illinois energy efficiency program is administered by the Illinois Department of Commerce and Economic Opportunity. There is no decoupling in Illinois at this time.

### LICENSURE REQUIREMENTS

To be an Alternative Retail Electric Supplier (ARES), a potential new supplier must petition the ICC for a Certificate of Service Authority. ARES's are also required to comply with state renewable portfolio standard and clean coal provision requirements.

An electric utility may offer any competitive service to any customer or group of customers without filing contracts with or seeking approval of the ICC, notwithstanding any rule or regulation that would require such approval. The ICC may not increase or decrease the prices and may not alter or add to the terms and conditions for the utility's competitive services from those agreed to by the electric utility and the customer. Non-tariffed, competitive services provided by utilities, however, are regulated only to the extent that ARES' are.

Agents, brokers and consultants engaged in the procurement or sale of retail electricity supply for third parties must be licensed. Meter services providers must also be certified by the ICC. Retail customers that own a cogeneration or self generation facility can seek certification to provide electric power under certain circumstances.

### CUSTOMER INFORMATION AND CONSUMER PROTECTION

#### Consumer Protection

Integrated distribution companies (IDCs) in Illinois are prohibited from using data they receive from their role as providers of transmission and distribution services to sell, promote, market or advertise any retail electric supply service or to attempt to obtain or retain any customer for any retail electric supply service.

On August 19, 2009, the ICC Commission directed by order that ICC staff submit a proposed first notice rule of consumer protections and education measures resulting from an ICC Office of Retail Market Development workshop (the ICC Staff Draft Rules). The ICC Staff Draft Rules, now in their second revision,<sup>62</sup> include several requirements:

1. Sales agents must meet specific training requirements.
2. A retail electricity provider must provide a uniform disclosure statement to the customer prior to any enrollment for electric service, regardless of the form of marketing used.
3. Additional delivery charges must be disclosed that may apply for contracts that do not change with the customer's usage (otherwise pricing flexibility not discussed).
4. Contracts may be cancelled by customers within 10 days of accepted enrollment without an early termination fee.
5. There should be restrictions on deposits.
6. Specific requirements for both automatic and non-automatic renewal (requiring specified notices and disclosures).
7. Restrictions on assignment.
8. Specific guidelines for marketing (by telephone, in person, telemarketing and over the Internet).

### **Customer Information and Competition**

The ICC has rules for functionally separated utilities and IDCs that provide that access to customer information must be made in a non-discriminatory manner. These rules include restrictions on electric utility merchant generation function access to a utility's customer-specific billing, usage or load shape data. The utility's merchant generation function must provide the "verifiable request" of a retail customer (or "verifiable authorization" as the customer's agent) before the data is provided. Data should be provided in the same manner it would be to a nonaffiliated ARES in similar circumstances. The merchant generation function must also be charged the same type of reasonable fee for the provision of customer-specific data that the electric utility charges to any nonaffiliated ARES.

An electric utility's merchant generation function may receive generic information concerning the usage, load shape or other general characteristics of customers by rate classification. Generic information by rate classification, however, may not be provided to the electric utility's merchant generation function in a discriminatory manner. No preference can be provided to the electric utility's merchant generation function over nonaffiliated ARES that make requests for such generic information by rate class.

In addition, no electric utility generation function employee may have unauthorized access to or receive data or information provided to the electric utility's transmission and distribution function by a nonaffiliated ARES, another electric utility, a customer of a nonaffiliated ARES or another electric utility, or a retail customer.

### **DISTRIBUTED GENERATION**

#### **Net Metering and Interconnection<sup>63</sup>**

Illinois rules require that a net metering facility be equipped with metering equipment that can measure the flow of electricity in both directions at the same rate. For eligible residential customers, this is typically accomplished through use of a single, bi-directional meter.<sup>64</sup>

<sup>62</sup> See the ICC Office of Retail Market Development Web site: <http://www.icc.illinois.gov/ormd/RESObligations.aspx> (last accessed Feb. 26, 2009).

<sup>63</sup> Also includes information from the Database of State Incentives for Renewables and Efficiency, available [www.dsireusa.gov](http://www.dsireusa.gov) (DSIRE Database).

The interconnection rules set four levels of review for interconnection requests. A project must meet all of the requirements of a given classification to be eligible for that level of expedited review. The level of review required is generally based on system capacity, whether system components are certified by a nationally recognized testing laboratory and whether the system is connected to a radial distribution circuit or to an area network.<sup>65</sup> Costs of upgrades shall be directly assigned to the interconnection customer whose distributed generation facility caused the need for the distribution upgrades.<sup>66</sup>

### Load Aggregation

Illinois law allows for aggregation, and aggregators, in fact, are included in the definition of an ARES. Electric utilities must allow the aggregation of loads that are eligible for delivery services. The electric utility must also allow aggregation for any voluntary grouping of customers, including, without limitation, those having a common agent with contractual authority to purchase electric power and energy and delivery services on behalf of all customers in the grouping. As detailed in H.B. 0722 (effective Jan. 1, 2010), municipalities and counties may also aggregate. Opt-out programs, it must be approved by a majority of the electors voting on the question. H.B. 0722 also provides for a process for soliciting bids for electricity provision and other related services.

### ILLINOIS STATEWIDE SMART GRID COLLABORATIVE

In 2008, the ICC established a statewide smart grid collaborative in the context of a rate proceeding.<sup>67</sup> In the *ComEd 2008 Rate Case Order*, ComEd requested rider recovery of AMI investments. Specifically, ComEd requested a regulatory mechanism that would “provide regulatory certainty about the prudence” of smart grid investments before they are made and allow recovery of ComEd’s capital costs. ComEd also proposed a preapproval process for smart grid projects. ComEd said the process would incorporate meaningful workshop participation by stakeholders and ICC approval of the specific projects proposed by ComEd.<sup>68</sup>

The ICC approved the rider for the limited purposes of the initial phase of ComEd’s planned AMI deployment plan. The ICC then ordered that a statewide smart grid collaborative (the “Collaborative”) involving the two large regulated investor-owned utilities, ICC Staff and other stakeholders, be established. The Collaborative was tasked with analyzing the results of the initial phase of ComEd’s deployment plan and was also required to consider the costs and benefits of smart grid implementation and developing a strategic plan by the fall of 2010. Upon presentation, the ICC may consider the strategic plan for adoption in a docketed proceeding. The ICC then stated that “[t]hereafter, ComEd may file a plan for implementation and re-file its request for rider recovery of smart grid investments.”<sup>69</sup>

The Collaborative was required to investigate a minimum set of policy initiatives.<sup>70</sup> The ICC also required that the analysis of benefits include: reductions in utility costs related to maintaining and operating a distribution system;

<sup>64</sup> See 220 ILCS 5/16-107.5. If the eligible customer’s existing electric revenue meter does not meet this requirement, the electricity provider shall arrange for the local electric utility or a meter service provider to install and maintain a new revenue meter at the electricity provider’s expense. For nonresidential customers, the electricity provider may arrange for the local electric utility or a meter service provider to install and maintain metering equipment capable of measuring the flow of electricity both into and out of the customer’s facility at the same rate and ratio, typically through the use of a dual channel meter. For generators with a nameplate rating of 40 kilowatts and below, the costs of installing such equipment shall be paid for by the electricity provider. For generators with a nameplate rating over 40 kilowatts and up to 2,000 kilowatts capacity, the costs of installing such equipment shall be paid for by the customer. Any subsequent revenue meter change necessitated by any eligible customer shall be paid for by the customer.

<sup>65</sup> *Order on its Own Motion, Consideration of Interconnection in Section 1254 of the Energy Policy Act of 2005*, “Second Notice Order,” ICC, Docket No. 06-0525 (Jun. 10, 2008) (the “*Second Notice Order*”).

<sup>66</sup> See the *Second Notice Order*.

<sup>67</sup> *Commonwealth Edison Company, Proposed General Increase in Electric Rates*, ICC, Docket No. 07-0566 (Sep. 10, 2008) (the “*ComEd 2008 Rate Case Order*”).

<sup>68</sup> *Id.* at p. 103.

<sup>69</sup> *Id.* at p. 143.

<sup>70</sup> Policies included: 1) definition of a smart grid and its functionalities; 2) principles Illinois should use to guide smart grid planning and deployment, for example, interoperability, open architecture, and non-discriminatory access; 3) uniform standards; 4) methods of estimating, calculating and assessing benefits and costs, including evaluation of nonquantifiable benefits (and costs); 5) implications of smart grid technology for future policies regarding rate design, consumer protection, and customer choice; 6) effect of statutory renewable resource, demand response and energy efficiency goals on smart grid planning and implementation; 7) consumer education and dissemination of information about smart grid technologies, demand response programs and alternative rate structures; 8) access by electricity market participants to smart grid functionalities; 9) data collection, storage, management, security, and availability to third parties; 10) standards for interconnection of third-party equipment; 11) mechanisms to flow through to customers any utility smart grid revenues; 12) adoption of new demand response

potential changes in consumer costs related to decreased energy consumption; reduced procurement costs; increased price responsiveness; and demand response.

Through several workshop proceedings the Collaborative is currently developing policy.<sup>71</sup> Policies that include the treatment of smart grid investment through rates, performance based incentives, customer information, consumer policy, technical standards, and specific AMI applications.<sup>72</sup>

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programs; and 13) open architecture and interoperability standards for technological connectivity to the RTO and/or independent system operator to which a utility may belong.

<sup>71</sup> See the Illinois Statewide smart grid Collaborative Web site at <http://www.ilgridplan.org/ISSGC%20KickOff%20Workshop%20Details/Forms/AllItems.aspx> (last visited Mar. 1, 2010).

<sup>72</sup> *Id.*

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## 9. State Analysis: Massachusetts

Massachusetts, after California, is one of the largest investors in energy efficiency in the nation. It has embraced certain incentives and plans for decoupling. Massachusetts has also mandated that utilities plan for TOU, real-time pricing and certain customer education measures.

### RETAIL MARKET OVERVIEW

Massachusetts is a restructured state with retail competition. Development of the retail markets during the first three years was slow. Utilities offered a generation Standard Offer Service with a 10 percent and then 15 percent discount that retail suppliers could not match. The competitive market for electric load ultimately made some progress, reaching 1.3 percent in December 1999, 5 percent in December 2000, and 14.4 percent in December 2001. (The increase is comprised mostly of large commercial customers.)

### INCENTIVES

Massachusetts has an Electric System Benefits Charge to fund DSM programs with an annual budget of \$120 million. A July 2008 Massachusetts Department of Public Utilities (MADPU) order required utilities to have operational decoupling plans by 2012. Massachusetts also recently ordered a straw proposal for a base revenue adjustment mechanism that renders electric and gas companies' revenue levels immune to changes in sales between rate proceedings.

### GREEN COMMUNITIES

The Green Communities Act of 2008, or S.B. 2768, requires distribution companies to file pilot program plans to the MADPU, including smart meters, automated load management systems embedded within current DSM programs, and remote status detection and operation of distribution system equipment. The Green Communities Act also mandates that required energy efficiency plans include "programs for public education regarding energy efficiency and demand management." The act also requires the Massachusetts Department of Energy Resources to collaborate with University of Massachusetts at Boston "to establish an educational outreach pilot program." The plans were approved on January 28, 2010.

S.B. 2768 also requires that utilities file proposals with MADPU to implement a pilot program that requires TOU or hourly pricing for commodity service for a minimum amount of customers. A specific objective of the pilot participants must be to reduce, peak and average loads by a minimum of 5 percent. MADPU is required to work with the EDCs to develop plans that provide for larger numbers of customers. Utilities that can show higher bill savings than outlined above are eligible to earn incentives. The plans were approved in January 2010. The TRC test is used to evaluate energy efficiency programs.

One pilot created under S.B. 2768 is called "energy pay and save," which allows electric utility customers to purchase and install energy-efficient products in their residences or commercial facilities by paying the cost of the system over time through an additional cost on the customer's electricity bill. Another pilot would assist consumers with the purchase of energy-efficient items for residential home modifications.

In 2000, the MADPU established policy guidelines on the pricing and procurement of default service, which included competitive procurement. Variable and fixed pricing options were established for default service customers.

### UPDATE ON PRIVACY IN MASSACHUSETTS

On March 1, 2010, new privacy regulations took effect in Massachusetts.<sup>73</sup> "Standards for the Protection of Personal Information of Residents of the Commonwealth" applies to all businesses (i.e., not only businesses

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<sup>73</sup> 201 C.M.R. 17.00.

based in Massachusetts) that collect and retain “personal information” from Massachusetts residents in connection with the provision of goods and services or for the purposes of employment. It includes requirements for safeguarding the security of computerized and non-computerized personal information. The regulations are considered some of the most detailed privacy regulations in the nation.

## 10. State Analysis: New Mexico

New Mexico is an example of a state that has recently become more aggressive in both energy efficiency and, to a lesser extent, smart grid deployment. It has set up an authority for renewable transmission. New Mexico has not embraced incentives—although it does have them on the DSM side—or decoupling, and also rejected an attempt to socialize meter replacement costs. The New Mexico Public Regulation Commission (NMPRC) is required by statute to identify and remove regulatory barriers and disincentives for public utility expenditures on energy efficiency and load management. New Mexico has a Renewable Portfolio Standard applicable to both public utilities and rural electric cooperatives.<sup>74</sup>

New Mexico has rules that restrain third-party arrangements for energy efficiency services. The law in New Mexico states that alternative energy efficiency providers must get utility and NMPRC consent to provide ratepayer-funded energy efficiency and load management to the utility's customers.<sup>75</sup>

### RETAIL MARKET OVERVIEW

In 2003, Gov. Bill Richardson signed S.B. 718, which repealed the Electric Utility Industry Restructuring Act of 1999, suspending restructuring in New Mexico.

### INCENTIVES AND RECOVERY

New Mexico does not utilize decoupling at this time but is currently investigating various incentives. In January 2008, the NMPRC opened a proceeding to investigate what effect incentives will have to motivate utilities to deploy energy efficiency and load management. In 2009, the NMPRC opened an investigation for the purpose of developing a service quality incentive mechanism for the four major investor-owned utilities operating in New Mexico—Public Service Company of New Mexico, Southwestern Public Service Company, El Paso Electric Company and New Mexico Gas Company.

Public utilities in New Mexico may recover the reasonable costs of complying with the renewable portfolio standard through the ratemaking process. A public utility also recovers its reasonable interconnection and transmission costs to deliver renewable energy to New Mexico retail customers. Costs that are consistent with commission-approved procurement plans or transitional procurement plans are deemed to be reasonable. The National Regional Planning Council rules allow electric utilities to provide economic development rates from excess capacity to qualified customers in their service area. Utilities are allowed some flexibility when applying economic development rates, which are designed to protect nonparticipating customers. New Mexico utilities' rates currently include TOU rates.

The NMPRC is required by statute to identify regulatory disincentives or barriers for public utility expenditures on energy efficiency and load management measures and ensure that they are removed in a manner that balances the public interest, consumers' interests and investors' interests.

The NMPRC is also required to provide public utilities with an opportunity to earn a profit on cost-effective energy efficiency and load management resource development that, with satisfactory program performance, is financially more attractive to the utility than supply-side utility resources. New Mexico requires the use of the TRC test when evaluating energy efficiency measures.

A public utility that undertakes cost-effective energy efficiency and load management programs has the option of recovering prudent and reasonable costs along with NMPRC-approved incentives for demand-side resources and load management programs through an approved tariff rider or in base rates or by a combination of the two. Program costs and incentives may be deferred for future recovery through creation of a regulatory asset. The only limit to the tariff rider or customer impact for any utility customer is that it shall not exceed \$75,000 dollars per

<sup>74</sup> See N.M.S.A. 1978, § 62-16-1.

<sup>75</sup> See N.M.S.A. 1978, § 62-17-7.

year without the customer's consent. Unless otherwise ordered by the NMPRC, a tariff rider approved by the commission must contain language on customer bills explaining program benefits.

In 2007, the New Mexico Supreme Court ruled that the NMPRC exceeded its authority in declaring renewable energy credits costs recoverable through an automatic adjustment clause.<sup>76</sup> In *NMI versus PRC*, the court stated that New Mexico allows utilities to recover reasonable compliance costs through the "ratemaking process." It then held that the "ratemaking process" refers to both general rate cases and automatic adjustment clauses, depending on the type of cost involved. Automatic adjustment clauses may be used to recover only "taxes or cost of fuel, gas or purchased power." The court also held that renewable energy credit costs are "purchased power." Therefore the NMPRC exceeded its authority in declaring these costs "closely related to purchased power" and thus recoverable through an automatic adjustment clause.

## METERS

New Mexico utilities own meters and determine meter investment strategy subject to the approval of the NMPRC. The NMPRC has recently rejected a meter replacement charge for a utility's meter replacement program.<sup>77</sup> In the *Picacho Hills* case, the NMPRC stated that as a matter of fairness to existing customers that have older meters, the utility should be required to recover the cost of its replacement meters by adding those costs to rate base. The NMPRC stated that it is the utilities' "responsibility, and not the customer's, to replace obsolete meters. Moreover, it is the entire system, and not individual customers with mechanical meters, that benefit from the replacement of the mechanical meters. Thus, the costs of replacing those older meters with the electronic meters should be allocated to all customers by adding those costs to rate base."<sup>78</sup> New Mexico also has extensive requirements for meter testing, billing and use. In 2006, the NMPRC opened a proceeding on advanced metering.<sup>79</sup>

## CUSTOMER INFORMATION AND EDUCATION

The NMPRC rules require that electric utilities include information in customer bills about the portion of the rates attributable to generation, transmission and distribution activity, respectively. This information is intended to educate customers about the various services being rendered by their electric utility and the cost of those services. Specific bill format is outlined, and there are requirements for bill inserts. In addition, utilities are required to develop a customer education plan that includes intended modes of communication and is subject to NMPRC review. In New Mexico a public utility is prohibited from selling or disclosing consumers' nonpublic personal information without the customer's permission.

## THIRD-PARTY ARRANGEMENTS FOR RENEWABLE ENERGY GENERATION

In June 2009, the NMPRC issued an order and a supplemental order assigning a hearing examiner to review whether third-party arrangements for renewable energy generation are permissible under New Mexico law. Issues include the permissibility of arrangements that involve leasing of distributed generation equipment from nonutility lessors to lessees that are also retail customers of utilities.<sup>80</sup>

On March 10, 2010, Gov. Richardson signed S.B. 190 that states that certain renewable-energy-distributed-generation facility owners and operators are not public utilities. The legislation allows third-party ownership or control of all or any part of a customer-sited renewable energy generation facility. Currently in New Mexico, with a public utility's consent, the NMPRC may allow for an alternative entity to provide ratepayer-funded energy efficiency and load management to customers of that public utility.<sup>81</sup>

<sup>76</sup> New Mexico Industrial. Energy Consumers v. PRC, 168 P.3d 105 (Aug 28, 2007) (NMI).

<sup>77</sup> In re Picacho Hills Utility Co., Inc., NMPRC, Case No. 07-00394-UT (Oct. 23, 2008) (Picacho Hills).

<sup>78</sup> Id. at Nos. 109-114.

<sup>79</sup> Notice of Inquiry into Advanced Metering, NMPRC, Case No. 06-00391-UT (Sep. 26, 2006).

<sup>80</sup> Press release, NMPRC, "NMPRC Issues Supplemental Order on Third-Party Arrangements for Renewable Energy," (Jun. 26, 2009), available at: <http://www.nmprc.state.nm.us/news/pdf/062309renewableadd09.pdf>.

<sup>81</sup> N.M.S.A. 1978, § 62-17-7.

The New Mexico statutes put forth that no public utility shall, as to rates or services, make or grant any unreasonable preference or advantage to any corporation or person within any classification, or subject any corporation or person within any classification to unreasonable prejudice or disadvantage. No public utility shall establish and maintain any unreasonable differences as to rates of service either as between localities or as between classes of service.

## **LOAD MANAGEMENT**

New Mexico utilities are required by statute to evaluate and implement cost-effective programs that reduce energy demand and consumption. The NMPRC must approve energy efficiency and load management programs before they are implemented. Utilities must also file periodic integrated resource plans with the NMPRC, identifying the most cost-effective portfolio of resources to supply the energy needs of customers.

In New Mexico, large customers can receive credits for certain expenditures made toward cost-effective energy efficiency and load management. Large customers can also receive exemptions to paying 70 percent of the tariff rider.

In 2008, Gov. Richardson signed H.B. 305. A among other things, the bill directs utilities to include load management and energy-efficiency measures in their resource portfolio and sets minimum thresholds for action. It also requires public utilities to file program evaluation reports every three years with the NMPRC.

## **NET METERING AND INTERCONNECTION<sup>82</sup>**

The NMPRC has required net metering since 1999, and the standards were revised in 2007. Systems of up to 80 MW are eligible to interconnect and net meter, as are PURPA “qualifying facilities.” This is significant to customers with large loads, such as universities or corporate campuses. Interconnection procedures adopted in July 2008 are in effect for systems less than or equal to 10 MW and systems larger than 10 MW. The rules also include a simplified interconnection process and application for systems less than or equal to 10 kW and a fast-track process for systems less than or equal to 2 MW.

## **RENEWABLE ENERGY TRANSMISSION AUTHORITY**

In 2007, the New Mexico Renewable Energy Transmission Authority Act created the New Mexico Renewable Energy Transmission Authority (NMRETA). The NMRETA’s stated purpose is to develop new transmission projects that promote renewable energy. It also aims to stimulate clean energy production and create high-paying jobs, capital investment and greater economic development in rural areas. NMRETA has bonding authority for financing of approved eligible projects, though it has yet to use it.

## **THE NEW MEXICO GREEN GRID INITIATIVE (NMGGI)**

Since 2008, New Mexico has been coordinating the working groups of several smart grid stakeholders (including colleges and government agencies) through the NMGGI. The goal of NMGGI is to vet a next generation smart grid for renewables to develop a system that is repeatable and scalable. The NMGGI then aims to work with industry and venture capitalists to begin implementing a green grid system across New Mexico within five years.

## **ADDITIONAL RENEWABLE ENERGY / ENERGY EFFICIENCY MEASURES**

New Mexico has undertaken some other initiatives in the area of energy efficiency that include the state’s Solar Rights and Solar Recordation Acts, which allow for the creation of solar easements for the purpose of protecting and maintaining proper access to sunlight. Such solar rights can be bought and sold separately from the property itself. The Solar Rights Act established the right to use solar energy as a property right, while the Solar Recordation Act outlines the procedure for filing a solar right. New Mexico also provides tax credits to incentivize

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<sup>82</sup> Includes information from the DSIRE Database.

the development of solar markets. In addition, New Mexico law allows for the issuance and sale of energy efficiency bonds.

In 2007, the New Mexico legislature passed the Sustainable Development Testing Site Act (SDTSA), which provides for the approval of areas to be used for nonindustrial research and testing to increase efficient energy use by residential development. The SDTSA sets out a permitting process for testing sites and states that county codes and ordinances are not applicable to certain research activities in an approved site.

The Renewable Energy Financing District Act,<sup>83</sup> passed in 2009, resulted in the Property Assessed Clean Energy (PACE) bond program. PACE financing spreads out the costs of energy improvements over a long period, thus reducing up-front capital expenditures on renewable energy.

New Mexico, like many states, has also enacted a variety of energy-efficiency incentives ranging from tax incentives to grant or loan programs. These include a clean energy grants fund targeting state institutions and both business and personal tax credits for renewables.

### **INNOVATIVE INTERNATIONAL AGREEMENT**

In 2009, Gov. Richardson signed a MOU with Japan that establishes a partnership between the state and Japan's New Energy and Industrial Technology Development Organization. NEDO committed to a four-year, \$30 million investment in microgrid and smart house demonstration projects. A microgrid/solar distributed generation project will be located at the Mesa del Sol residential/commercial development near Albuquerque. Smart meters, utility-scale photovoltaics and a smart feeder will be deployed in Los Alamos County. In 2010, NEDO announced the selection of 19 Japanese companies, including Toshiba, Kyocera and Hitachi, as partners in these projects.

Under the Japan-U.S. joint project, initiated by Japan's New Energy and Industrial Technology Development Organization and the government of New Mexico, large photovoltaic devices and power storage cells will be installed at some 1,000 households in the state in the autumn of 2010. A system will then be created to monitor via the Internet power consumption around the clock and control two-way flows of power.

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<sup>83</sup> See N.M.S.A. 1978, § 5-18-1.

## 11. State Analysis: New York

While New York has not enacted smart grid specific statutes like California or required AMI penetration as aggressively as Pennsylvania, New York has long been active in the area of energy efficiency and demand response.

### RETAIL MARKET OVERVIEW

New York is a restructured state with retail competition. In late 1997 and early 1998, the New York Public Service Commission (NYPSC) approved rate and restructuring plans for its major utilities.<sup>84</sup> Utilities were allowed to recover lost revenues due to retail migration to the new energy service companies (ESCOs) from ratepayers.<sup>85</sup> In 2008, the NYPSC determined that the state's retail access markets were sufficiently developed to warrant modification of some retail access policies and practices.<sup>86</sup> Cost recovery, however, was maintained.

### METERS AND PRICING

In 1997 and 1999, the NYPSC issued orders allowing for certain electric customers to own their meters.<sup>87</sup> The orders allowed for competitive electric meters to be provided by authorized meter service providers (MSPs) and meter data services to be provided by meter data service providers (MDSPs).<sup>88</sup> Electric utilities were required to file tariffs providing interval meters to large commercial and industrial customers for mandatory time-differentiated rates and voluntary time-differentiated rates to other electric customers. The NYPSC has also approved residential AMI programs for New York's major utilities, many of which are expected to be supported by ARRA funds.

The NYPSC has established a policy that electric utilities should invest in new AMI only if cost savings relative to current practice can be substantiated. In addition, new investments should not create new, additional stranded costs or be anticompetitive in nature.<sup>89</sup> In 2006, the NYPSC directed electric utilities to file comprehensive and cost-effective advanced metering systems plans.<sup>90</sup>

During the course of the plan review, the NYPSC determined that common criteria were needed to evaluate the plans and support their development. In 2008, the NYPSC sponsored a technical conference on advanced metering infrastructure and solicited comments. The culmination of the process was an order issued in February 2009, establishing minimum functional requirements for AMI systems.<sup>91</sup> In July 2009, the NYPSC authorized the recovery by utilities of eligible ARRA project costs through the imposition of a surcharge while reserving the authority to judge the prudence of the project expenditures.<sup>92</sup>

All meters and associated devices used for the purpose of customer billing must be approved by the NYPSC.<sup>93</sup> Meters and ancillary products must be tested with NYPSC-recognized equipment and be within specific operating

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<sup>84</sup> Namely, Consolidated Edison Company of New York, Inc. (Con Edison), Central Hudson Gas & Electric Corporation (Central Hudson), Orange and Rockland Utilities, Inc. (O&R), New York State Electric and Gas Corporation (NYSEG), Rochester Gas and Electric Corporation (RG&E) and National Grid. See NYPSC 1998-1999 Annual Report, available at: [http://www.dps.state.ny.us/annual\\_rpt/Annual\\_Report\\_98\\_99.PDF](http://www.dps.state.ny.us/annual_rpt/Annual_Report_98_99.PDF).

<sup>85</sup> Case 07-M-0458, "Competitive Retail Energy Markets, Order on Review of Retail Access Policies and Notice Soliciting Comments," NYPSC, Apr. 24, 2007 at p. 3.

<sup>86</sup> Case 07-M-0458, "Order Determining Future of Retail Access Programs," NYPSC, Oct. 27, 2008. For example, the NYPSC directed utilities to continue or implement ESCO referral and purchase of accounts receivables programs so long as the costs of such programs are not borne by ratepayers.

<sup>87</sup> Cases 94-E-0952, 00-E-0165, 02-M-0514, "Order Relating to Electric and Gas Metering Services," NYPSC, Aug. 1, 2006 at p. 3.

<sup>88</sup> MSPs and MDSPs must submit an application pursuant with the "New York Practices and Procedures for the Provision of Electric Metering in a Competitive Environment" in order to provide services.

<sup>89</sup> *Id.*

<sup>90</sup> *Id.*

<sup>91</sup> Case 09-M-0074, "Order Adopting Minimum Functional Requirements for Advanced Metering Infrastructure Systems and Initiating an Inquiry into Benefit-Cost Methodologies," NYPSC, Feb. 13, 2009.

<sup>92</sup> Cases 09-E-0310, 09-M-0074, "Order Authorizing Recovery of Costs Associated With Stimulus Projects," NYPSC, Jul. 27, 2009.

<sup>93</sup> New types of meters must conform to the requirements specified in "Acceptable Performance of New Types of Electricity Meters and Instrument Transformers," of the latest version of the American National Standard Code for Electricity Metering. See 16 NY ADC 93.3.

specifications.<sup>94</sup> Jurisdictional utilities, ESCOs, MSPs or nonresidential customers that qualify for the host utility's mandatory TOU rates may apply for meter approval.<sup>95</sup> Manufacturers may also apply, provided that each manufacturer's application is accompanied by a statement certifying that it intends to use the type of meter in its application. The NYPSC retains the authority to rescind meter approvals.<sup>96</sup>

## INCENTIVES AND ENERGY EFFICIENCY

New York is implementing decoupling on a utility-by-utility basis. In 2007, the NYPSC directed utilities to develop proposals for a true-up-based delivery service revenue decoupling mechanisms for consideration in individual utility rate cases.<sup>97</sup> The NYPSC also oversees incentive programs designed to increase utility safety and reliability and penalizes companies for failing to meet safety and reliability standards. New York has had a Systems Benefits Charge (SBC) since 1998 to fund public policy initiatives that are not expected to be adequately addressed by New York's competitive electricity markets.<sup>98</sup> The SBC is administered by the New York State Energy Research and Development Authority (NYSERDA), a public benefit corporation.

New York has aggressively implemented energy efficiency initiatives. The NYPSC proceeding to implement the state's energy efficiency portfolio, initiated in 2008, invited NYSEDA and the six large investor-owned electric utilities to submit electric energy efficiency program proposals.<sup>99</sup> The NYPSC approved 45 electric energy efficiency programs between 2009 and 2010.<sup>100</sup> In addition, in May 2009 the NYPSC initiated a proceeding on a pilot on-bill financing project for energy efficiency programs.<sup>101</sup> The NYPSC has been working with several New York utilities, most notably including National Grid, to develop on-bill financing pilots.

NYSERDA also offers incentives to offset the cost of participation in demand response programs.<sup>102</sup> Equipment includes load shedding controls and automation equipment, new generator installation and existing generator modification.

In addition, the New York Power Authority (NYPA) and the Long Island Power Authority (LIPA) both invest in energy efficiency. NYPA, New York's state-owned electric utility that provides low-cost power for resale, has cumulatively invested more than \$1 billion in energy efficiency and clean generation projects,<sup>103</sup> including the financing and administration of more than 1,500 energy-efficient projects in government buildings, schools and other public facilities throughout New York, resulting in the annual reduction of electricity consumption by 946,000 MWh.

LIPA, a nonprofit municipal electric provider, owns the retail electric transmission and distribution system on Long Island and is the nation's second largest municipal electric utility.<sup>104</sup> In 2008, LIPA announced its Efficiency Long Island program. The 10-year, \$924 million program offers residential and business customers an array of incentives and programs to reduce energy use. By 2018, Efficiency Long Island is expected to reduce peak electric demand by 500 MW.<sup>105</sup>

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<sup>94</sup> See 16 NY ADC Part 92.

<sup>95</sup> 16 NY ADC 93.5.

<sup>96</sup> 16 NY ADC 93.8.

<sup>97</sup> Cases 03-E-0640, 06-G-0746, "Order Requiring Proposals for Revenue Decoupling Mechanisms," NYPSC, Apr. 20, 2007.

<sup>98</sup> See NYPSC web site at: <http://www3.dps.state.ny.us/W/PSCWeb.nsf/All/58290EDB9AE5A89085257687006F38D1?OpenDocument>. Programs include those for energy efficiency, energy-related research and development, energy programs targeted at low income customers and environmental disclosure activities.

<sup>99</sup> Cases 08-E-1132, 07-M-0548, "Order Approving Electric Energy Efficiency Programs with Modifications," NYPSC, Jun. 24, 2009. New York's energy efficiency portfolio seeks to reduce electricity usage by 15% of forecast levels by the year 2015, with comparable results in natural gas conservation. The NYPSC has established interim targets and funding through the year 2011. See the NYPSC web site at: <http://www3.dps.state.ny.us/W/PSCWeb.nsf/ArticlesByTitle/06F2FEE55575BD8A852576E4006F9AF7?OpenDocument>.

<sup>100</sup> See NYPSC web site at: <http://www3.dps.state.ny.us/W/PSCWeb.nsf/ArticlesByTitle/06F2FEE55575BD8A852576E4006F9AF7?OpenDocument>.

<sup>101</sup> Cases 06-G-1185, 06-G-1186, 07-M-0548, 09-M-0465, "Notice of New Proceeding on a Pilot On-Bill Financing Program," NYPSC, May 27, 2009. Niagara Mohawk has already begun implementing a form of on-bill financing as part of its Small Business Services Energy Efficiency Program.

<sup>102</sup> "Demand Response Incentives," NYSEDA, available at [http://www.nyserda.org/programs/Existing\\_facilities/demand.html](http://www.nyserda.org/programs/Existing_facilities/demand.html).

<sup>103</sup> New York State, Public Service Commission, available at: [http://www.dps.state.ny.us/07M0548/workgroups/inventory/WG2\\_PS\\_NYPA\\_programs\\_overview.pdf](http://www.dps.state.ny.us/07M0548/workgroups/inventory/WG2_PS_NYPA_programs_overview.pdf).

<sup>104</sup> Among municipal electric utilities, LIPA has the nation's second largest electric revenues. See the LIPA web site at: <http://www.lipower.org/company/profile/>.

<sup>105</sup> See the LIPA web site at: [http://www.lipower.org/newscenter/pr/2008/050808\\_eli.html](http://www.lipower.org/newscenter/pr/2008/050808_eli.html).

## CUSTOMER PROTECTION AND INFORMATION

New York has had a specific consumer protection statute since 1981. The Home Energy Fair Practices Act (HEFPA) states that the continued provision of gas, electric and steam service to residential customers without unreasonable qualifications or lengthy delays is both necessary for the preservation of the health and general welfare and is in the public interest. In 2002, HEFPA was amended to include ESCOs and any other entity that provides gas and electric service to residential customers. ESCOs are subject to similar late-fee caps and budget billing plan requirements as utilities. Prepayments and deposits are also restricted.

New York also has Uniform Business Practices (NYUBP) to provide for consistent business procedures for ESCOs and utilities. They state, among other things, consumer protections and communications protocols between ESCOs and utilities. The NYUBP also regulate aspects of the relationship between ESCOs, MSPs and MDSPs.

The NYUBP specify what provisions must be in consumer contracts, and mandate disclosure. ESCOs must submit samples of all forms and contracts to the NYPSC as part of their ESCO application in addition to meeting credit and data operability standards.

ESCOs must obtain customer consent to request information from a utility or MDSP. ESCOs are required to inform customers of the types of information to be obtained, to whom it will be given, how it will be used and how long the authorizations will be valid. The authorization is valid for no longer than six months unless the sales agreement provides for a longer time.<sup>106</sup> Upon valid request, ESCOs will receive a customer's service history, which includes a specific information.<sup>107</sup> ESCOs are not authorized to sell customer information received from MDSPs unless it is necessary for the provision of service.<sup>108</sup>

The NYPSC also developed practices and procedures for MDSPs and MSPs.<sup>109</sup> They include eligibility requirements, dispute resolution procedures and service standards. The New York Competitive Metering Practices also delineate the service responsibilities vis-a-vis MDSPs, MSPs and utilities,<sup>110</sup> including standards for meter compatibility, installation points, service and repair. The New York Competitive Metering Practices also allocate the costs of meter tests in the case of a dispute. If the meter does not meet standards of accuracy, the MSP pays for the test. If the meter is accurate, the party requesting the test bears the cost, provided that customer costs do not exceed \$50.

<sup>106</sup> NYUBP 2009, Section 4.

<sup>107</sup> The electric set includes: (1) customer's service address; (2) electric or gas account indicator; (3) sales tax district used by the distribution utility; (4) rate service class and subclass or rider by account and by meter, where applicable; (5) electric load profile reference category or code, if not based on service class; (6) usage type, reporting period, and type of consumption (actual, estimated or billed); (7) 12 months, or the life of the account, whichever is less, of customer data via EDI and, upon separate request, an additional 12 months, or the life of the account, whichever is less, of customer data via EDI or an alternative system at the discretion of the distribution utility or MDSP, and, where applicable, demand information; (8) if the customer has more than one meter associated with an account, the distribution utility or MDSP shall provide the applicable information, if available, for each meter; and (9) electronic interval data in summary form (billing determinants aggregated in the rating periods under a distribution utility's tariffs). See NYUBP 2009, Section 4.

<sup>108</sup> *Id.*

<sup>109</sup> New York Practices and Procedures for the Provision of Electric Metering in a Competitive Environment (NY Competitive Metering Practices), NYPSC, May 9, 2001, available at: [http://www.dps.state.ny.us/esco\\_metering\\_manual.pdf](http://www.dps.state.ny.us/esco_metering_manual.pdf). These practices and procedures are established pursuant to an order in Case 94-E-0952, NYPSC, Jun. 16, 1999, which determined that electric metering shall be furnished competitively to large customers.

<sup>110</sup> The New York Practices and Procedures for the Provision of Electric Metering in a Competitive Environment state, among other things, that: (1) physical metering and metering services, consisting of the installation, maintenance, testing and removal of meters and related equipment is opened to competition by MSPs; (2) meter data services, consisting of meter reading, meter data translation, and customer association, validation, editing and estimation are also opened to competition- these services being provided, either individually or in combination, by MDSPs; (3) the responsibility for meter services and meter data services will reside with either the customer's MSP/MDSP or utility; (4) the utility shall be the provider of last resort (POLR) for metering and meter data services; (5) utilities, MSPs and MDSPs are required to adhere to applicable procedures, performance standards and regulations relative to the provision of metering services; (6) Customers with demands of 50 kW or greater for two consecutive months during the most recent twelve consecutive months may obtain competitively-provided billing meters and associated metering and meter data services; (7) meter removals for the purpose of intentionally disconnecting electric service for any reason may only be performed by the utility; (8) customers who elect to procure competitive meter services shall be required to procure both meter services and meter data service competitively. Utilities are not required to offer meter data services to customers who competitively procure only meter services and/or partial meter data services, nor are they required to offer metering services to customers who competitively procure only meter data services; (9) staff will monitor the provision of metering services regardless of the entity providing such services; (10) notwithstanding any other Commission rules or orders to the contrary, the rights, duties and obligations of the utility concerning meter reading, estimated bills, and back billing found in 16 NYCRR Part 13 shall not apply to customers who utilize a competitive meter provider; and (11) until the implementation of electronic data interchange in New York, the parties are responsible for developing mutually agreeable mechanisms for transmitting data.

## NEW YORK INDEPENDENT SYSTEM OPERATOR (NYISO) DEMAND RESPONSE PROGRAMS<sup>111</sup>

NYISO regulates day-ahead and real-time markets for electricity. NYISO has EDRP and SCR programs, in addition to a day ahead demand response program (DADRP) and demand-side ancillary services program (DSASP).<sup>112</sup>

The EDRP and SCR programs are to be deployed in energy shortage situations to maintain the reliability of the bulk power grid by empowering NYISO to shut down large power users in exchange for payment.<sup>113</sup> EDRP reductions are voluntary, while SCR participants agree to reduce their power usage and are paid in advance. During a heat storm in the summer of 2006, NYISO's demand-response programs resulted in nearly 1,000 MW of load reduction for five hours, reducing the state's peak load by about 3 percent.<sup>114</sup>

DADRP allows energy users to bid their load reductions into the day-ahead energy market as generators do.<sup>115</sup> Offers deemed "economic" are paid at the market clearing price. DSASP allows qualified retail customers to bid their load curtailment capability into the day-ahead and/or real-time markets.<sup>116</sup>

## NET METERING AND DISTRIBUTED GENERATION

New York's 1999 interconnection requirements were some of the nation's first.<sup>117</sup> The initial requirements were limited to systems rated up to 300 kW connected to radial distribution systems. The requirements were modified in 2005 to include interconnection to radial and secondary network distribution systems with capacities up to 2 MW.<sup>118</sup>

New York's original net-metering law, enacted in 1997, applied only to residential photovoltaic (PV) systems up to 10 kilowatts kW. The law was expanded in 2002 to include generation from farm biogas with rated capacity of up to 400 kW, and a 2004 amendment included some residential and farm-based wind turbines. Legislation in 2008 (S.B. 7171, S.B. 8415, and S.B. 8481) expanded net metering eligibility to non residential PV and wind systems. New York's net metering law was amended again in 2010 by A.B. 7557 to remove a provision limiting the size of non-residential wind and solar facilities to the on-site peak load.<sup>119</sup>

In 2007, the NYPSC exempted a planned 3.6 MW distributed generation facility whose facilities crossed public streets to serve multiple users from regulation under state law.<sup>120</sup> The facility, owned by Burrstone Energy and now installed, crosses a public street to provide electricity and heat to a nursing home, a hospital and Utica College. Burrstone Energy stated to the NYPSC that the facility qualified as a Federal QF. PURPA, however, does not authorize a QF to make retail sales of electricity, which may be subject to state regulation. The facility, therefore, also sought to qualify as an exempt co-generation facility under New York law.<sup>121</sup> In an extension of previous rulings exempting facilities that crossed public land, the NYPSC applied the state co-generation exemption to the Burrstone Energy facility. The NYPSC also ruled that state law contemplated multiple users and does not require that users share property ownership rights to qualify for the exemption.<sup>122</sup>

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<sup>111</sup> Information also provided by "Electric Energy Efficiency and Marketing of Conserved Energy in Selected Jurisdictions," A Report to the Empresa de Pesquisa Energética, prepared by Dewey & LeBoeuf LLP, Apr. 1, 2010 (on file with authors).

<sup>112</sup> "Demand Response Programs," NYISO, available at [http://www.nyiso.com/public/markets\\_operations/market\\_data/demand\\_response/index.jsp](http://www.nyiso.com/public/markets_operations/market_data/demand_response/index.jsp).

<sup>113</sup> *Id.*

<sup>114</sup> Harnessing the Power of Demand: How ISOs and RTOs Are Integrating Demand Response into Wholesale Electricity Markets, ISO/RTO Council (Oct. 16, 2007), at 37-38.

<sup>115</sup> Demand Response Programs, NYISO, available at [http://www.nyiso.com/public/markets\\_operations/market\\_data/demand\\_response/index.jsp](http://www.nyiso.com/public/markets_operations/market_data/demand_response/index.jsp).

<sup>116</sup> *Id.*

<sup>117</sup> See Environmental Protection Agency web site at: <http://www.epa.gov/CHP/state-policy/interconnection.html>.

<sup>118</sup> *Id.*

<sup>119</sup> See [www.dsireusa.org](http://www.dsireusa.org).

<sup>120</sup> Case 07-E-0802, Burrstone Energy Center LLC, "Declaratory Ruling on Exemption from Regulation," NYPSC, Aug. 28, 2007.

<sup>121</sup> *Id.* See also New York Public Service Law §§ 2(2-a) and 2(2-d).

<sup>122</sup> *Id.* at 5.

## THE NEW YORK STATE SMART GRID CONSORTIUM (NYSGC) AND PLANYC

In 2008, Gov. Patterson announced the formation of the NYSGC, which aims to foster the development and deployment of new technology that reduces the cost of electricity and increases reliability. It is comprised of leaders from government, utility companies and universities, as well as consumers, and released a draft strategic plan in 2009.<sup>123</sup>

In addition, New York City Mayor Bloomberg launched a plan to “green” New York City in 2007. Called “PlaNYC,” the plan includes initiatives to promote peak load management by expanding smart meters and real-time pricing throughout the city.<sup>124</sup>

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<sup>123</sup> Available at: [http://nyssmartgrid.com/download/general/StratVis\\_TechPlan\\_Draft\\_v2\\_Oct2009.pdf](http://nyssmartgrid.com/download/general/StratVis_TechPlan_Draft_v2_Oct2009.pdf).

<sup>124</sup> See the PlaNYC web site at: <http://www.nyc.gov/html/planyc2030/html/plan/energy.shtml>.

## 12. State Analysis: Ohio

Ohio has a relatively aggressive smart grid law and regulation. Recent state law mandates that utilities use time-sensitive pricing and the creation of infrastructure modernization plans.

### RETAIL MARKET OVERVIEW

Ohio's restructuring law took effect on Jan. 1, 2001, and provided a five-year market development period in which utilities' rates were frozen to allow a competitive resale market to develop. To transition from the five-year plans, the Public Utilities Commission of Ohio (PUCO) developed rate stabilization plans with Ohio utilities. In 2008, the Ohio legislature passed S.B. 221 to keep electric rates stable going forward INCLEAR as the rate stabilization plans expired. S.B. 221 devised a system under which rates would be set by the PUCO beginning in 2009, and outlined a path for electric utilities to implement market-based pricing.

In addition, electric distribution utilities must provide a standard service offer (SSO) to all customers who do not choose another supplier. An electric utility may propose an SSO under either or both of two methods—the market-based option or the cost-based option, both of which must be approved by the PUCO. Under the market-based option, a utility meeting certain criteria may propose an auction to be conducted under PUCO rules. Under the cost-based option, a utility may propose an electricity security plan that provides for recovery of prudently incurred fuel and purchased power costs. The legislation contains benchmarks for alternative energy resources as a component of an SSO.

### RATES AND INCENTIVES

Under Ohio law, a public utility is allowed to recover its operating expenses, plus a reasonable return on its infrastructure investments, from customers. S.B. 221 established state policy to encourage time-differentiated pricing and AMI implementation. It requires EDCs to file electric security plans (ESPs) that may propose a distribution infrastructure modernization plan. S.B. 221 allows the use of single-issue ratemaking for the plans plus incentives for the utility's recovery of costs, including lost revenue, shared savings and avoided costs, and a just and reasonable rate of return on such infrastructure modernization.

### ADVANCED METERING

The PUCO adopted the EAct 2005 metering and communication standard and directed EDCs to offer all customers a rate option that distinguishes at least on-peak/off-peak, plus a TOU meter for customers choosing that rate. It also directed PUCO staff to study the costs and benefits of AMI deployment strategies. The EAct 2005 adoption describes time-differentiated and dynamic-pricing options to be offered. It also requires applications for infrastructure modernization plans to describe communication infrastructure, metering, distribution automation or other applications it supports, as well as benefits, costs, performance milestones and metrics.

Ohio utilities are also required to file anti-theft and anti-tampering plans with the PUCO. Service can be disconnected due to fraudulent acts. Utilities must obtain consent to release customer account numbers and social security numbers (except in certain situations).

Ohio has an advanced energy fund to provide financial, technical and related assistance for advanced energy projects in this state.

### AGGREGATION

Ohio's laws allow for communities to aggregate. The governmental aggregator chooses an outside supplier for all of the customer members in its group. Aggregations can be formed to buy natural gas, electricity or both. Governmental aggregators buying electricity must be certified by the PUCO.

Aggregation can be opt in or opt out. If opt-in aggregation is chosen, the local government can then develop a plan and start signing up customers. The plan must include all rates and terms for customers to consider when deciding to join.

A majority of voters are required to authorize opt-out aggregation. If authorized, the local government must form a plan of operation and management and hold at least two public hearings. Once the plan is adopted, each customer to be aggregated must be notified that they will be automatically enrolled in the program unless they specifically elect not to participate. The local government must allow anyone enrolled in the program an opportunity to opt out every two years without paying a switching fee.

## **RENEWABLE ENERGY/ENERGY EFFICIENCY**

In 2009, the PUCO required each electric utility to create an energy-efficiency and peak-demand reduction program portfolio. In 2009, the PUCO adopted rules putting into practice the annual benchmarks that electric utilities and service companies must meet to fulfill Ohio's alternative energy portfolio standard. By the year 2025, 25 percent of electricity sold by these companies must be generated from alternative energy sources, and at least half of this energy must come from renewable energy sources like wind, solar and hydro.

The new PUCO rules also require electric utilities to deploy cost-effective energy-efficiency measures and require electric generating facility owners in Ohio to report greenhouse gas emissions to The Climate Registry. The PUCO also established a process for electric generation facilities to become certified as renewable generation resource facilities. In 2009, the PUCO certified 73 such facilities across Ohio.

## **UTILITY EXPERIENCE WITH S.B. 221**

The PUCO approved AEP-Ohio's ESP in March 2009. The company's plan sets electric generation rates through 2011 and demonstrates the gridSMART® program to improve reliability, reduce costs and allow customers to better control their electric bills through advanced metering.

FirstEnergy's ESP was also approved in March 2009. The PUCO approved an agreement that establishes electric generation rates through a competitive auction process until May 2011. FirstEnergy plans to expand energy efficiency and DSM programs and will commit \$25 million to economic development in Ohio.

In June 2009, the PUCO approved an agreement that extended Dayton Power & Light's existing generation rate plan through 2012. The plan will lead to minimal rate increases and allow the company to anticipate rising fuel costs, implement energy efficiency measures and construct advanced energy infrastructure. The PUCO approved Duke Energy Ohio's ESP in 2008.

In 2009, FirstEnergy and Duke Energy received PUCO approval to increase rates for electric distribution service. Distribution charges pay for the costs associated with delivering electricity to customers' homes and businesses.

In January 2009, the PUCO authorized FirstEnergy to increase its rates for electric distribution for each of the company's three subsidiaries. The Commission also directed FirstEnergy to provide discounted distribution rates to schools. This was FirstEnergy's first distribution rate increase since 1996.

In July 2009, the PUCO approved an agreement between Duke Energy Ohio, PUCO staff and the Ohio Consumers' Counsel allowing Duke to increase rates for electric distribution service. The agreement also includes funding for low-income customer energy efficiency and bill payment assistance.

## **OHIO ARRA PROJECTS**

In 2009, Ohio utilities and communities were awarded more than \$250 million in ARRA funding for smart grid-related projects.

AEP-Ohio will utilize more than \$75 million in ARRA funds to develop a secure, interoperable and integrated smart grid regional demonstration program. The project will affect more than 100,000 customers and is intended to create approximately 500 jobs. Duke Energy Business Services was awarded \$200 million to complete a comprehensive grid modernization of its Midwest electric system encompassing Ohio, Indiana and Kentucky. FirstEnergy Service Company in Akron was awarded \$57.4 million to modernize its electrical grid and deploy a smart meter network to reduce peak energy demand.

## **CUSTOMER EDUCATION AND INFORMATION**

The PUCO was required to undertake customer education programs regarding restructuring by statute. The Ohio rules specify the necessary minimum service requirements of an electric utility, an electric services company and an electric cooperative. They include a prohibition against unfair, deceptive and an unconscionable acts and practices in the marketing, solicitation, and sale of such a competitive retail electric service and in the administration of any contract for service.

Utilities are required to provide consumers with adequate, accurate and understandable pricing, terms and conditions of service, including any switching fees, and with a document containing the terms and conditions of pricing and service before the consumer enters into the contract for service.

The rules also require disclosure of the conditions under which a customer may rescind a contract without penalty and the terms identifying how customers may switch or terminate service (including any required notice and penalties). Bills must also be standardized. Competitive electric service providers have separate billing requirements for fixed and variable rates. There are restrictions on when and how service providers can market to customers. In addition, service providers are required to give the PUCO copies of advertising materials upon request.

## **GENERATION AND AGGREGATION**

Service quality, safety and reliability requirements for electric generation service are determined primarily through market expectations and contractual relationships. There are also requirements to disclose certain aspects of the resource mix used. Ohio utilities are required to cooperate with certified load aggregators.

## 13. State Analysis: Pennsylvania

Pennsylvania, through the use of mandates, has made great strides into AMI. Consequently the state has some of the highest rates of smart meter penetration in the country. Not surprisingly, Pennsylvania has comprehensive rules regarding the technical requirements of meters.

### RETAIL MARKET OVERVIEW

Pennsylvania is a restructured state with retail competition. The 1996 Electric Generation Customer Choice and Competition Act required Pennsylvania electric distribution companies (EDCs) to unbundle transmission, distribution and generation rates for retail customers. The Pennsylvania Public Utilities Commission (PAPUC) monitors the retail electric generation market to prevent market power abuse and discriminatory conduct.

### SMART GRID: RECENT STATUTORY REQUIREMENTS

In 2008, the Pennsylvania legislature enacted Act 129, which mandated both: (1) the development of a statewide energy efficiency and conservation program and (2) the adoption of smart meter technology and TOU rates. It also required the provision of default service pursuant to a PAPUC approved "competitive procurement plan" employing one or more statutorily defined approaches with a "prudent mix" of spot market purchases, short-term contracts and long-term contracts (i.e., four to 20 years and not to exceed 25 percent of supply unless approved by the PAPUC).

Act 129 required EDCs with at least 100,000 customers to adopt and implement a cost-effective energy efficiency and conservation plan to reduce energy demand and consumption. Each EDC was also required to file a plan for the replacement of all of its meters over the next 15 years (or sooner upon an individual customer's request and payment of cost, and on all new construction). The EDC plans were filed and approved with modifications and are expected to be finally approved and implemented in 2010. Smart meter compliance plans were filed with decisions expected in early 2010.

Utility compliance with Act 129 requirements is to be verified by an independent statewide evaluator using the TRC test. The PAPUC must submit a five-year plan by November 30, 2013, which provides for the establishment of further energy efficiency and demand-side requirements applicable after May 31, 2013, that pass the TRC Test.

### METERS

Act 129 requires that smart meter technology must be capable of bi-directional communication and be able to record electricity usage at least hourly. It must also provide customers with direct information on hourly consumption, enable TOU rates and real-time pricing, and effectively support automatic control of consumption by the customer or at the customer's request, by the EDC or a third party. The PAPUC has interpreted the smart meter capability requirements of Act 129 as minimal requirements, and has directed that a covered EDC's smart meter technology must support additional capabilities.<sup>125</sup>

While a public utility's sale of appliances or equipment is not normally within jurisdiction of the PAPUC, Pennsylvania does place some restrictions on the sale of equipment by public utilities to the public. These include

<sup>125</sup> Smart meters must also support: (1) bi-directional data communications capability; (2) remote disconnection and reconnection; (3) ability to provide 15-minute or shorter interval data to customers, EGSs, third-parties and the RTO on a daily basis, consistent with the data availability, transfer and security standards adopted by the RTO; (4) a minimum of hourly reads delivered at least once per day; (5) on-board meter storage of meter data that complies with nationally recognized nonproprietary standards such as ANSI C12.19 and C12.22 tables; (6) open standards and protocols that comply with nationally recognized nonproprietary standards, such as IEEE 802.15.4; (7) ability to upgrade these minimum capabilities as technology advances and becomes economically feasible; (8) ability to monitor voltage at each meter and report data in a manner that allows EDC to react to the information; (9) remote programming capability; (10) communicating outages and restorations; (11) net metering of customer-generators; (12) automatic load control by EDC, customer and third parties, with customer consent; (13) time-of-use and real-time pricing programs; and (14) providing the customer direct access to consumption and pricing information. See *Smart Meter Procurement and Installation*, "Implementation Order," PAPUC, Docket No. M-2009-2092655 (Jun. 18, 2009) at pp. 16-17 (the "PA Smart Meter Implementation Order").

prohibitions on (1) discontinuing service for a customer's failure to pay for the equipment and (2) applying deposits to the purchase price (unless it is for meter damages). Separate accounts must be kept when a utility sells (or employs officers to sell) such equipment.

Under Act 129, utilities have proposed spreading most smart meter costs equally to all customers within each class via a monthly surcharge. Act 129 creates an exception for customers who request smart meters before their scheduled deployment. Those customers must pay the upfront cost of the new meter installation. The proposed costs of early meter installation vary significantly and can be high. PECO's proposed cost for early installation is \$16, while Duquesne Light Company's is \$1,305.<sup>126</sup>

### “SMART RATE” STRUCTURE, INCENTIVES AND COST RECOVERY

The PAPUC has the authority to approve flexible pricing and rates, including negotiated, contract-based tariffs designed to meet the specific needs of a utility customer and to address competitive alternatives. The PAPUC may also use performance-based rates as an alternative to existing rate-base/rate-of-return ratemaking.

An EDC may recover smart meter technology costs through (1) base rates, including a deferral for future base rate recovery of current basis with carrying charge as determined by the Commission; or (2) on a full and current basis through a reconcilable automatic adjustment clause. All measures associated with an EDC's smart metering plan shall be financed by the customer class that receives the benefit of such measures. In addition, the PAPUC has interpreted Act 129 to mean that a customer must pay the costs of installing a meter at the time of the request and that only the incremental costs over and above the cost for system-wide deployment are to be paid by customers requesting early deployment of a smart meter.<sup>127</sup>

Decoupling is not in use in Pennsylvania at this time. There appears to be a legal debate on how far the PAPUC may go in authorizing it. The statutory language limiting certain cost recovery of losses due to decreased energy consumption or reduction in demand is footnoted below.<sup>128</sup>

In March 2010, the PAPUC approved a TOU metering plan proposed by PPL, but imposed a condition requiring the utility to absorb any revenue losses stemming from lowered consumption under the program.<sup>129</sup> As a result, PPL officials have stated that they are uncertain as to how they will proceed with the TOU program.<sup>130</sup>

In 2009 the PAPUC, at the request of Gov. Edward Rendell,<sup>131</sup> initiated an investigation, which will include an inquiry into decoupling<sup>132</sup> regarding the policies and actions, that should be implemented to ensure compliance with the requirements of Section 410(a) of the American Recovery and Reinvestment Act which requires the PAPUC to consider ratemaking policies that align with the promotion of energy efficiency and conservation. This will include an inquiry into decoupling.<sup>133</sup>

<sup>126</sup> Sonny Popowski (Pennsylvania Consumer Advocate), “Distribution Infrastructure and Electricity Transformation,” a presentation to the Harvard Electricity Policy Group (Feb. 15, 2010), available at: [http://www.hks.harvard.edu/hepg/Papers/2010/Popowsky\\_Sonny\\_HEPG\\_Feb2010.pdf](http://www.hks.harvard.edu/hepg/Papers/2010/Popowsky_Sonny_HEPG_Feb2010.pdf).

<sup>127</sup> *PA Smart Meter Implementation Order* at pp. 10-11.

<sup>128</sup> See 66 Pa.C.S.A. §§ 2806.1(k)(2)-(3); §2807(f)(4). Specifically, 66 Pa.C.S.A. § 2806.1(k)(2)-(3) states that “(1) An electric distribution company shall recover on a full and current basis from customers, through a reconcilable adjustment clause under section 1307, all reasonable and prudent costs incurred in the provision or management of a plan provided under this section. This paragraph shall apply to all electric distribution companies, including electric distribution companies subject to generation or other rate caps. (2) Except as set forth in paragraph (3), decreased revenues of an electric distribution company due to reduced energy consumption or changes in energy demand shall not be a recoverable cost under a reconcilable automatic adjustment clause. (3) Decreased revenue and reduced energy consumption may be reflected in revenue and sales data used to calculate rates in a distribution-base rate proceeding filed by an electric distribution company under section 1308 (relating to voluntary changes in rates).” 66 Pa.C.S.A. §2807(f)(4) states “In no event shall lost or decreased revenues by an electric distribution company due to reduced electricity consumption or shifting energy demand be considered any of the following: (i) A cost of smart meter technology recoverable under a reconcilable automatic adjustment clause under section 1307(b), except that decreased revenues and reduced energy consumption may be reflected in the revenue and sales data used to calculate rates in a distribution rate base rate proceeding filed under section 1308 (relating to voluntary changes in rates). (ii) A recoverable cost.”

<sup>129</sup> Jeff Beattie, PPL, Pennsylvania PUC Find Demand Response Hard to Do, *The Energy Daily*, Apr. 12, 2010.

<sup>130</sup> *Id.*

<sup>131</sup> Letter of Gov. Edward G. Rendell to PAPUC Chair James H. Cawley (Mar. 23, 2009).

<sup>132</sup> *Id.*

<sup>133</sup> *Compliance of Commonwealth of Pennsylvania with Section 410(a) of the American Recovery and Reinvestment Act of 2009*, PAPUC, Decision No. I-2009-2099881 (Apr. 16, 2009).

## CUSTOMER INFORMATION AND CONSUMER PROTECTION

Act 129 requires EDCs with customer consent, to make available to third parties, including electric generation suppliers (EGSs) and providers of conservation and load management services, direct access to meter and electronic meter data. The PAPUC did not require, however, that EDCs (who own the meters) allow customers or their designated agents to tamper or physically access the meter itself.

EGSs and EDCs must comply with the PAPUC's rules concerning privacy of customer information, which allow customers to restrict the release of historical billing data if the customer opts to do so.

All EDCs and third parties must comply with PAPUC orders relating to electronic data communications and the approved Internet protocol. This includes requirements that third parties must be tested according to specified standards and certified with the EDC.

EGSs, including brokers, marketers and aggregators, are to obtain licenses from the Commission to sell electricity or related services to retail customers in Pennsylvania.

Pennsylvania requires disclosure when electric generation supply service is initiated, when a supplier proposes changing the terms of service or when service commences from a default service provider. The required disclosure statement in the stat includes specific reference to variable pricing. Pennsylvania electric distribution companies were also required by statute to implement consumer education programs informing customers of the changes in the electric utility industry.

Pennsylvania also mandates minimum requirements for EGS and distribution company contracts. Variable pricing statements, where applicable, must include conditions of variability (the basis on which prices will vary) and limits on price variability. Customers get a three-day recession period after disclosure is given.

Electric generation suppliers and distribution companies must follow a code of conduct set out by statute. This code includes a prohibition on discriminatory conduct with respect to customer information and the processing of service requests. In addition, Pennsylvania requires suppliers to provide disclaimers to customers against tying between affiliated companies.

## DISTRIBUTED GENERATION

### Default Service

As discussed above, Act 129 required revision of Pennsylvania's competitive procurement plans for default service. On January 10, 2010, the PAPUC instituted a rulemaking to consider amendments to its default service regulations as required by the enactment of Act 129. Currently, the default service provider shall offer residential and small business customers a generation supply service rate that shall change no more frequently than on a quarterly basis. All default service rates shall be reviewed by the commission to ensure that the costs of providing service to each customer class are not subsidized by any other class.

### Load Aggregation

The PAPUC approved the implementation of an opt-out retail aggregation bidding program in the service territory of an electric distribution utility whose customers experienced unprecedented rate increases.<sup>134</sup> In *Direct Energy*, Pike County's PAPUC-approved auction for provider-of-last-resort (POLR), service resulted in a 70 percent increase in POLR rates. The increase in rates was attributed to several factors, including the lack of retail competition. The opt-out program was adopted as a solution to the specific problem of rate increases in Pike County and was not meant to be seen as a precedent in future proceedings.

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<sup>134</sup> Re *Direct Energy Services*, PAPUC, Docket No. P-00062205, (Apr. 20, 2006) (*Direct Energy*).

In March 2010, the Pennsylvania House of Representatives Consumer Affairs Committee held hearings regarding draft legislation that would allow for municipal aggregation in Pennsylvania. The draft legislation would allow opt-out municipal aggregation to consumers of electricity within a municipality's boundaries.

### **Net Metering and Interconnection**<sup>135</sup>

In Pennsylvania, investor-owned utilities must offer net metering to residential customers who generate electricity with systems up to 50 kW in capacity, nonresidential customers with systems up to three MW in capacity and customers with systems greater than three MW but no more than five MW who make their systems available to the grid during emergencies, or where a microgrid is in place in order to maintain critical infrastructure.

Net metering is available when any portion of the electricity generated is used to offset on-site consumption (i.e., system size is not limited by the customer's on-site load). Net metering is achieved using a single bi-directional meter that can measure and record the flow of electricity in both directions at the same rate. The utility must provide this meter if a customer's existing meter does not meet these requirements. If a customer agrees, a dual-meter arrangement may be substituted for the bi-directional meter. Virtual meter aggregation on properties owned or leased and operated by a customer-generator is allowed for purposes of net metering.

The Pennsylvania regulations provide that to prevent interclass or intra-class cost shifting, a net-metered, small commercial or industrial customer is responsible for its share of stranded costs if its self-generation results in a 10 percent or more reduction in electricity purchase.

Pennsylvania's interconnection standards include provisions for four levels of interconnection for generators up to five MW in capacity. The standards allow a single point of interconnection for a location with multiple generators. Limited interconnection to area networks is permitted. The approved application fee schedule also allows utilities to charge the customer for the cost of grid upgrades that are necessary to accommodate the system and costs of up to \$100/per hour associated with system impact, feasibility or facility studies. Utilities are not permitted to deviate from the fee structure described above without an agreement from the PAPUC that such a deviation is appropriate.

Customer generators must provide an accessible external disconnect switch or access to a disconnect switch through a lock-box system. The customer generator must pay for the disconnect switch. However, customer generators are not required to carry liability insurance.

On March 12, 2009, the PAPUC—joined by the public service commissions of District of Columbia, Maryland, Delaware, and New Jersey—submitted a letter to PJM seeking its support of demand response compensation principles for PJM's Economic Load Response Program. These public service commissions recommended that PJM consider the following three principles when determining how to compensate and incentivize demand response: (1) that incentives do not automatically sunset; (2) a 15 percent demand response payment threshold; and (3) when looking at compensation for different types of rates (i.e., variable and fixed), consider the overall impact of uniform versus rate type compensation.

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<sup>135</sup> See [www.dsireusa.gov](http://www.dsireusa.gov).

## 14. State Analysis: Texas

Texas, perhaps after California, is considered one of the most aggressive states for smart grid deployment in the nation. Texas statutes encourage the quick deployment of AMI, and Texas utilities are allowed to recover the costs of smart meters through a surcharge. Texas utilities are making large investments in AMI. Consequently, Texas has extensive rules regarding technical requirements for smart meters. As discussed below, the Texas rules also allow for competitive metering. Given its aggressive AMI deployment, the Texas experience with competitive metering will be important to watch as meter implementation strategies evolve.

### RETAIL MARKET OVERVIEW

Three areas in Texas are not served by Electric Reliability Council Of Texas (ERCOT), and retail competition is not permitted in these areas (i.e., the service territories of Entergy Texas and El Paso, and that portion of Texas served by the Southwest Power Pool). During 2008 and early 2009, more than 60 percent of Texas retail load in areas served by ERCOT was served by alternative energy suppliers, including more than 40 percent of residential load.

### SMART METERS

Smart meters are not mandated in Texas and are voluntary pursuant to the Public Utility Commission of Texas (PUCT) rules. Texas utilities are, however, empowered to recover costs through a meter surcharge and are engaging in large smart meter investments. Oncor announced it reached a settlement with the PUCT to begin its rollout of 3 million smart meters throughout its delivery system in north Texas by 2012. As part of the smart meter plan, residential customers would pay a surcharge of less than \$2.35 per month for 11 years. Oncor will be requesting permission from the state regulator to allow the company to distribute monitors to low-income consumers free of charge.

CenterPoint Energy Houston Electric received approval for an advanced meter information network under which smart meters and related infrastructure were to begin March 2009. Smart meters were to be installed beginning with 145,000 units in 2009, 500,000 units in 2010 and every year thereafter until all 2.2 million customers in the Center Point area have the new units. The system is expected to cost about \$640 million to deploy. Customers will be charged \$3.24 per month for two years before the fee drops to \$3.05 per month for ten years, coming to a total of \$443.76 average cost per customer.

Minimum functionality requirements include automated meter reading, two-way communications, remote disconnect/reconnect, capability to provide 15-minute interval data daily, real-time access to usage data, open standards, and capability to communicate with in-premise devices that monitor usage and control loads. While provision of smart meters is voluntary, there are requirements for how they are used in tariffs if implemented. The PUCT is also currently investigating impacts on markets and ensuring that consumers receive benefits of AMI investment, including web portals, HAN, access to consumer data and related security, and customer education.

Texas has specific rules regarding meter tampering, and the burden of proof of meter tampering lies with the utility. Texas also has specific rules regarding meter testing, location and reading.

In March of 2010, the PUCT refused to halt the installation of more than 5 million smart meters in homes throughout the state, saying that complaints of high bills had more to do with cold weather than faulty meters.<sup>136</sup> The PUCT did, however, agree that the meters should be tested by an independent third party.

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<sup>136</sup> "Texas Regulators Refuse to Halt Smart Meter Installation," Platt's Electricity Daily (Mar. 5, 2010). See also Memorandum in Response to Senator T. Frasier, PUCT, (Mar. 3, 2010).

## COMPETITIVE METERING

Texas has rules establishing the terms and conditions for competitive metering services to be offered to commercial and industrial customers served by investor-owned transmission and distribution utilities (TDUs). A commercial or industrial retail customer may choose a meter owner, and the owner may be the retail customer, a retail electric provider, the TDU or another person authorized by the customer. The current retail customer owns all meter data related to the premises it occupies, regardless of who the meter owner is. The current retail customer also has the right to physical access to the meter and can also assign meter data.

ERCOT keeps a list of meters that qualify as competitive meters and are required to be capable of providing the data necessary for billing in accordance with the TDU's tariff. Meters that do not meet standards must be taken out of service. It is required that the competitive meters be adjusted to the condition of zero error. If a meter not owned by the TDU is found not to meet standards, the TDU is required to install a temporary replacement (with the meter owner being responsible for related charges). The costs for testing meters lie with the requestor. Costs for meter tests requested by the customer, Retail Electric Provider (REP), competitive meter owner or TDU shall be the responsibility of the requesting party in accordance with the TDU's tariff. When a request is made to test a meter that is subsequently found not to meet commission-approved standards for accuracy, however the cost of the meter test shall be the responsibility of the meter owner.

Both the TDU and the REP have the right and capability, including necessary security passwords, to access meter data for the purpose of rendering a bill, complying with settlement rules of an independent organization, or load research and load profiling. The TDU is responsible for the security of the data used for settlement and TDU billing and must maintain the meter programming password capable of altering such billing parameters. No entity other than the TDU has the right, capability or meter programming password to alter the data collected by the meter for the purpose of TDU billing. A TDU's requirements for load research must not have the effect of limiting the type or frequency of meter data available to an end-use customer. TDUs are required to file a tariff that provides a competitive metering service credit to the REP of a customer that selects a meter owner other than the TDU.

## RETAIL SERVICE PROVIDERS (REP) AND COMPETITION

Texas law states that "a transmission and distribution utility may not participate in the market for electricity except to serve its own needs."<sup>137</sup> In addition, a person or retail electric utility cannot provide service in the service area of an electric cooperative or municipally owned utility that has not adopted customer choice<sup>138</sup>

REPs are required to be certified with the PUCT. The PUCT will grant certification to applicants that demonstrate the following: (1) the financial and technical resources to provide continuous and reliable electric service to customers in the area for which the certification is sought; (2) the managerial and technical ability to supply electricity at retail in accordance with customer contracts; (3) the resources needed to meet the customer protection requirements; and (4) ownership or lease of an office located in Texas for the purpose of providing customer service. Retail service providers must comply with customer protection provisions, disclosure requirements and marketing guidelines.

Texas utilities may not discriminate against a person who or electric cooperative that sells or leases equipment or performs services in competition with the electric utility or engages in practices that tend to restrict or impair that competition. Providers of aggregation services must register with the PUCT.

## INCENTIVES

Texas utilities are not permitted to establish rates or tariffs that automatically adjust and pass through to the utility's customers a change in the utility's fuel or other costs. The PUCT, however, is authorized to allow

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<sup>137</sup> V.T.C.A., Utilities Code § 39.105.

<sup>138</sup> *Id.*

incentives, specifically: (1) recovery of the reasonable costs of conservation, load management and purchased power; and (2) additional incentives for conservation, load management, purchased power and renewable resources.

In Texas, utilities may undertake market transformation programs, which are strategic efforts to provide incentives and education to reduce market barriers for energy-efficient technologies and practices.

In 2007, H.B. 3696 empowered the PUCT to establish a cost-recovery mechanism for utilities that install AMI and report biennially on progress, barriers and recommendations. H.B. 3967 encourages smart grid networks to be deployed as rapidly as possible. It also established AMI deployment plan requirements and an expedited process for cost-recovery surcharges for deployment that meets minimum functional criteria. In December 2009, the PUCT approved the advanced metering plan of AEP Texas, including an advanced metering system surcharge.

## **CUSTOMER PROTECTION**

The Texas statutes include what reads like a “customer bill of rights” and states that customers are entitled to the following (1) to be informed about rights and opportunities in the transition to a competitive electric industry; (2) choose the customer’s retail electric provider consistent with this chapter, to have that choice honored, and to assume that the customer’s chosen provider will not be changed without the customer’s informed consent; (3) have access to providers of energy efficiency services, to on-site distributed generation, and to providers of energy generated by renewable energy resources; (4) to be served by a provider of last resort that offers a commission-approved standard service package; (5) receive sufficient information to make an informed choice of service provider; (6) to be protected from unfair, misleading or deceptive practices, including protection from being billed for services that were not authorized or provided; and (7) to have an impartial and prompt resolution of disputes with its chosen retail electric provider and transmission and distribution utility.

## **CUSTOMER INFORMATION**

In Texas, an electric utility shall provide a customer, the customer’s retail electric provider (REP), and other entities authorized by the customer, read-only access to the customer’s advanced meter data, including meter data used to calculate charges for service, historical load data, and any other proprietary customer information. The access shall be convenient and secure, and the data shall be made available no later than the day after it was created. The requirement to provide access to the data begins when the electric utility has installed 2,000 advanced meters for residential and nonresidential customers.

An electric utility shall use industry standards and methods for providing secure customer and REP access to the meter data. The electric utility shall have an independent security audit of the mechanism for customer and REP access to meter data conducted within one year of initiating such access and promptly report the results to the commission. A customer may authorize its data to be available to an entity other than its REP.

Utilities in Texas are required to provide several types of information to applicants when they request new service or transfer service, including the utility’s alternate rate schedules and options, time of use rates and renewable energy tariffs, if available. Some information, including information regarding customer rights as to rates and services must be provided in both English and Spanish.

Texas rules require that all customers in residential and commercial classes including low-income customers, have access to efficiency programs. Industrial customers must have access to programs that were developed and implemented prior to May 1, 2007, to the extent that such customers meet the criteria for participation in load management standard offer programs. Such programs must be completed by Dec. 31, 2008.

## 15. GLOSSARY OF DEFINED TERMS

|   |    |
|---|----|
| AMI – advanced meter infrastructure .....   | 14 |
| ARES – Alternative Retail Electric Supplier .....                                 | 44 |
| ARRA – 2009 American Recovery and Reinvestment Act .....                          | 17 |
| CAISO – California Independent System Operator .....                              | 33 |
| CL&P – Connecticut Light and Power .....  | 39 |
| ComEd – Commonwealth Edison .....   | 44 |
| Con Edison – Con Edison Company of New York, Inc .....                            | 66 |
| COPUC – Colorado Public Utility Commission .....                                  | 15 |
| CPCN – Certificate of Public Convenience and Necessity .....                      | 10 |
| CPUC – California Public Utilities Commission .....                               | 32 |
| DADRP – Day-Ahead Demand Response Program .....                                   | 57 |
| DOE – U.S. Department of Energy .....   | 18 |
| DPUC – Department of Public Utility Control .....                                 | 39 |
| DSASP – Demand-Side Ancillary Services Program .....                              | 57 |
| DSIRE Database – Database of State Incentives for Renewables and Efficiency ..... | 45 |
| DSM – demand-side management .....  | 37 |
| EDCs – electric distribution companies .....                                      | 40 |
| EGSs – electric generation suppliers .....  | 64 |
| EISA 2007 – 2007 Energy Independence and Security Act .....                       | 17 |
| EPA 2005 – 2005 Energy Policy Act .....   | 16 |
| ERAM – Electric Rate Adjustment Mechanism .....                                   | 9  |
| ERCOT – Electric Reliability Council of Texas .....                               | 9  |
| ESCOs – energy service companies .....  | 54 |
| ESPs – electric security plans .....  | 59 |
| EWGs – Exempt Wholesale Generators .....  | 16 |
| FEECA – Florida Energy Efficiency and Conservation Act .....                      | 42 |
| FERC – Federal Energy Regulatory Commission .....                                 | 12 |
| FLPSC – Florida Public Service Commission .....                                   | 41 |
| H.B. – House Bill .....   | 14 |
| HEFPA – Home Energy Fair Practices Act .....                                      | 56 |
| ICC – Illinois Commerce Commission .....  | 44 |
| IDCs – integrated distribution companies .....                                    | 44 |
| IOUs – investor-owned utilities .....   | 32 |
| LIPA – Long Island Power Authority .....  | 55 |
| LSE – load-serving entities .....   | 11 |

|  |    |
|--|----|
| MADPU – Massachusetts Department of Public Utilities .....                 | 48 |
| MDSPs – Meter Data Service Providers .....                                 | 54 |
| MSPs – Authorized Meter Service Providers .....                            | 54 |
| NEDO – New Energy and Industrial Technology Development Organization ..... | 53 |
| NERC – North American Electric Reliability Corporation .....               | 19 |
| NIST – National Institute of Standards and Technology .....                | 18 |
| NMGCI – New Mexico Green Grid Initiative .....                             | 53 |
| NMPRC – New Mexico Public Regulation Commission .....                      | 50 |
| NMRETA – New Mexico Renewable Energy Transmission Authority .....          | 52 |
| NYISO – New York Independent System Operator .....                         | 55 |
| NYPA – New York Power Authority .....                                      | 55 |
| NYPSC – New York Public Service Commission .....                           | 54 |
| NYSEG – New York State Electric and Gas Corporation .....                  | 54 |
| NYSERDA – New York State Energy Research and Development Authority .....   | 55 |
| NYSGC – New York State Smart Grid Consortium .....                         | 58 |
| NYUBP – New York Uniform Business Practices .....                          | 56 |
| O&R – Orange and Rockland Utilities, Inc .....                             | 54 |
| PAPUC – Pennsylvania Public Utilities Commission .....                     | 11 |
| PG&E – Pacific Gas and Electric .....                                      | 17 |
| POLR – provider of last resort .....                                       | 64 |
| PPL – PPL Corporation .....  | 9  |
| Public Service – Public Service Company of Colorado .....                  | 10 |
| PUCO – Public Utilities Commission of Ohio .....                           | 59 |
| PUCT – Public Utility Commission of Texas .....                            | 14 |
| PUHCA – Public Utility Holding Company Act .....                           | 16 |
| PURPA – Public Utility Regulatory Policies Act .....                       | 16 |
| QFs – Qualified Facilities .....   | 16 |
| REP – retail electric provider .....                                       | 67 |
| RG&E – Rochester Gas and Electric Corporation .....                        | 54 |
| RIM – Rate Impact Measure .....  | 42 |
| RTOs – Regional Transmission Organizations .....                           | 3  |
| S.B. – Senate Bill .....   | 33 |
| SBC – Systems Benefits Charge .....  | 55 |
| SCE – Southern California Edison .....                                     | 32 |
| SDG&E – San Diego Gas and Electric .....                                   | 32 |
| SDTSA – Sustainable Development Testing Site Act .....                     | 53 |

SSO – standard service offer .....59  
TDUs – transmission and distribution utilities .....67  
TOU – time-of-use .....9  
TRC – Total Resource Cost .....39  
UI – United Illuminating .....39

