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AZ CORP COMMISSION
DOCKET CONTROL

MARK B. BONSALL
General Manager and
Chief Executive Officer

July 15, 2013

Arizona Corporation Commission
DOCKETED

JUL 15 2013

DOCKETED BY

Chairman Bob Stump
Commissioner Gary Pierce
Commissioner Brenda Burns
Commissioners Susan Bitter Smith
Commissioner Bob Burns
Arizona Corporation Commission
1200 West Washington
Phoenix, AZ 85007-2996

RE: Initial Comments of the Navajo Transitional Energy Company, L.L.C. in Docket No. E-00000W-13-0135: *In The Matter of the Commission's Inquiry into Retail Electric Competition*

Dear Honorable Commissioners,

1) SRP prides itself on providing reliable low cost power to its nearly one million customers. We believe the current regulatory construct provides Arizona with the best possible platform to move into the future. In our attached comments, we address a variety of shortcomings that we see in the so called deregulated markets but I wanted to highlight our primary concern which is the adverse impact to long-term reliability and resource decisions.

   The most important product of the electric system, by any measure, is reliability. Electricity is the commodity, but reliability is the most important product. Reliability in energy supply enables the economy to operate well and robustly, and assuring future reliability in energy supply is a fundamental precondition for economic growth.

   By its very definition, reliability is achieved by intentionally and perpetually maintaining a targeted margin of excess capacity on the grid – so that if one resource goes down (either generation, or transmission), another is there to back it up. This means that if the temperature hits 119° F, sufficient resources are available such that AC units can continue to operate, and factories continue to produce their products; our reliability also ensures that if economic growth accelerates, it will not be retarded by insufficient energy supply.

However, consistently maintaining necessary capacity on the grid, by definition, cannot be supported by "deregulated" prices. Supply must exceed demand by a certain margin in order to secure reliability, and yet that very condition - supply consistently exceeding demand - leads to prices in a deregulated market insufficient to pay off the investment necessary to achieve the desired level of capacity. Thus, the conundrum-capital investment for reliability, and "deregulation", are incompatible. Deregulation is a disincentive to the investment required for reliability. This simple fact – this obvious conundrum – is why experiment after experiment at "deregulation" in the electric industry have failed.

Clearly there are those that will argue this point. However, in SRP's own experience, during the deregulation experiment in Arizona around the turn of the century proves otherwise. SRP deferred capital investment in the grid given the uncertainty surrounding our future revenue stream. What reserves we had were knowingly diminished to a substantially lower level. This is what happened before in Arizona, it is what has happened elsewhere in the country, and it is what will happen again in Arizona, if we unwisely move down the road of deregulation. It was not until the uncertainty surrounding future revenues was eliminated by the collapse of deregulation in California, and then Arizona, that SRP resumed normal and substantial investment in grid reliability.

2) While deregulation is a disincentive to investment in grid reliability, those investments that may be made will tend to be shorter term options, and tend to be made only when "shortage" prices are high enough to justify them, absent some other mechanism (many mechanisms have been tried in order to stimulate capital investment, which is why "deregulation" is really restructuring of the industry – simply devising new structures to do what incumbent utilities already do). In other words, given the uncertainty around revenues, options that are heavily capital intensive and/or take long lead times are not likely to be considered. "Quick fixes", with shorter paybacks, will tend to be preferred, thus, deregulation tends to turn long term planning of energy supply into a fairly meaningless academic exercise.

3) Deregulation's disincentive to long term investments will directly impact SRP's efforts to assure continued operation of the Navajo Generating Station ("NGS") - a critically important resource for the entire State of Arizona. The NGS story is quite complex, and we will not repeat it here. Our purpose in pursuing life extension for NGS, however, is to "keep Arizona whole." Keeping Arizona whole means keeping the jobs associated with the plant; the economic benefits to the tribes; the benefits to Arizona's water supplies; fuel diversity in the state's resource mix; and a long term low cost generation resource for future generations. SRP faces several years of intense work, and potentially hundreds of millions of dollars of incremental investment in order to "keep Arizona whole". We will not have the organizational capacity to get this critical job done if we have to deal, yet again, with deregulation. Moreover, the investment that will be necessary to create a reasonable future for NGS will simply likely not be made given uncertainty as to SRP's load (retail demand) and attendant revenues. We expect the

investment to be substantial, and that deregulation would make the investment risk too high.

4) Deregulation, and the effort it took to implement it the first time, consumed the entire strategic focus of SRP for several years. The dismantling of deregulation – including the resolution of post-deregulation litigation – went on for years thereafter, and consumed yet more organizational focus – all purely wasteful. This is not a hypothetical – this was our actual experience. Deregulation sounds simple, but isn't. Consider the time and work it took from a regulatory and statutory point of view. That was followed by stranded cost determinations – another highly complex undertaking, the comprehensive redesign of pricing structures, the development of new transactional computer systems, the creation of the Arizona Independent Scheduling Administration, etc. Restructuring Arizona's energy supply is a literally gigantic and all-consuming effort – and we must ask, to what end?

5) Other than what you can count on one hand, we are not hearing any clamoring for the consideration of deregulation from any of SRP's customers. Our prices are attractive, our service consistently award-winning, our reliability high, our customer options numerous, our technology cutting edge, our community involvement deep and wide, and our communications extensive and consistent. Against this context, it seems that restructuring the entire energy infrastructure of the State of Arizona is a solution in search of a problem.

There are innumerable other concerns in relation to restructuring (deregulation). They are addressed in the attached position paper and responses to the questions posed by the Commission.

In summary, however, we find reconsideration of restructuring (deregulation), which has quite obviously failed, in Arizona, California and in the United States generally, to be extremely problematic as to reliability, as to resource planning, and as to the future of the Navajo Generating Station. For the reasons set forth above and in the attached, we urge the Commission to terminate consideration of this proposal at the earliest possible moment.

Mark Bonsall

Enclosure: Position Paper of the Salt River Project

BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP
Chairman
GARY PIERCE
Commissioner
BRENDA BURNS
Commissioner
BOB BURNS
Commissioner
SUSAN BITTER SMITH
Commissioner

IN THE MATTER OF THE COMMISSION'S INQUIRY INTO RETAIL ELECTRIC COMPETITION.	Docket No. E-00000W-13-0135

SRP'S COMMENTS REGARDING RETAIL ELECTRIC COMPETITION IN ARIZONA

In its letter of May 23, 2013 in this Docket the Commission requested that interested parties provide detailed comments communicating their views on retail electric competition in Arizona. Salt River Project Agricultural Improvement and Power District provides these comments as an interested party. SRP first gives an overview of its position, then answers the 18 questions posed by the Commission.

RESPECTFULLY SUBMITTED this 15th day of July, 2013.

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Position Paper of the Salt River Project

Docket No. E-00000W-13-0135

July 15, 2013

This paper sets out the position of the Salt River Project on the issue of whether Arizona should resuscitate the deregulation of the electric industry. In summary, for the reasons explained below, explained in the material responsive to the questions posed by the Commission, and explained in SRP's previous filings on the issue, SRP opposes the proposal to resurrect deregulation in Arizona. SRP asks that the Commission close this docket.

This discussion is supported by the materials set forth in SRP's January 30, 2009 position paper submitted in Dockets E-0000A-02-0051 and E-0000A-01-0630 (attached hereto), and the materials provided here in response to the eighteen questions posed by the Commission.

1. <u>The Rise and fall of Deregulation</u>.

In 1996 Arizona jumped on the California bandwagon of electric deregulation. In theory it seemed like a good idea. After all, deregulation seemed to be working in the trucking, airlines and communications industries.

But, it was nothing more than a theory. Fortunately, California went first. It established a central market, a central transmission organization, and forced its utilities to sell most of their generation. Before Arizona's experiment really got off the ground, California's failed spectacularly. Arizona, logically, stopped deregulation in its tracks.

Since that time Arizona electric customers have done quite well. Arizonans are fortunate to have low energy prices, award winning customer service, a wide variety of service options and stable and reliable service. Arizona residents as a whole are not clamoring for deregulation. It is reasonable to conclude that Arizona's stable and well run electric systems have been a major contributor to Arizona's growth and success.

Nonetheless, at the urging of a small group led by out-of-state power marketers, Arizona has twice reexamined the issue of deregulation. These were significant efforts. In 2002 the Commission posed 113 questions (including subparts), many of them similar to those being posed today. Each stakeholder (mostly the same entities participating in this docket) provided detailed and researched answers to the questions. Following this process the Commission, in Decision No. 65154 (the "Track A decision"), suspended the requirement of divestiture, a major feature of deregulation. The Commission took no action to reinstate deregulation.

In 2009, following the suspension of the application of Sempra Energy Services for a competitive CC&N, the Commission carefully looked at the same issues, again posing questions to the stakeholders. As with the 2002 review, the stakeholders responded with carefully researched and documented responses. SRP provided an analysis of the risks and benefits of deregulation, and examined the experience in each state that had or was trying deregulation[1]. SRP also submitted testimony from experts in the industry[2]. The Staff Report issued in the docket suggested that nothing should be done without a detailed analysis of the risks. Again, the Commission took no action.

2. <u>The Situation Today</u>

In the years since the deregulation idea was first hatched, electric service in Arizona has continued to be delivered by local companies who own and operate diverse portfolios of generation assets dedicated solely to providing reliable service to Arizona customers. Arizona has experienced great success, as manufacturers, businesses, residents and visitors flock to our state. As Arizona has addressed every challenge that it has faced, it has prospered.

Other states were not so fortunate. They see continued change and experimentation with their electric systems, as the inherent flaws of deregulation are patched in dysfunctional markets. We can say that deregulation *worked* in these markets, if the measure of success is that the lights are still on. But, we cannot make the statement when we look at the long-term reliability risks, an over reliance on natural gas as a fuel, price stability and price levels, bloated bureaucracies, and significant costs.[3]

Today the electric industry landscape is much different from that of the 1990s. It is an understatement to say that the electric industry is undergoing rapid change. Much of this change is outside the control of the Arizona utilities and this Commission. A major effect of these industry changes is that it is becoming more difficult, even without restructuring and retail competition, to plan investments in and operate a reliable electric system. This is a challenge to all of us. The common goal of all Arizonans *must* be to manage change in the interests of Arizona's electric customers and economic interests. Arizona cannot afford unnecessary diversions from this overriding objective.

In the following sections we show how Arizona's modern goals to address industry change are inconsistent with the dated concept of deregulation. Here are some of the major industry challenges being faced by Arizona:

1. Increasing Pressure on Fossil Fuels, Particular Coal Fueled Generation

The federal government and the EPA continue to place significant pressure on the existing coal-fueled generation serving Arizona. The people and the businesses of Arizona, and Arizona's economy, rely on the reliability and low cost energy provided by these coal-fueled generating facilities. The jobs created by these facilities and the mines that provide

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[1] SRP's position paper is attached as Exhibit 1.
[2] The SRP testimony was actually submitted in proceeding to consider the Sempra Energy Services application for a competitive CC&N.
[3] SRP discusses price levels, costs and market dysfunction in the deregulated markets in its response to the eighteen questions.

their fuels are a major source of employment for the Hopi and Navajo people. The Navajo Generating Station provides inexpensive and reliable power to the Central Arizona Project for water delivery to central Arizona.

Arizona must develop a concerted position that recognizes the need for environmental improvement yet protects those assets that are important to Arizona.

2. Economic Growth

Thankfully the economy of Arizona is growing once again. This renewed growth brings new residents and businesses. But, with growth comes a premium on long term planning. Arizona must ensure that it properly plans for the future, and is not left short in this very competitive environment.

3. Increases in Distributed Generation, Mainly Solar Photovoltaic

As the price of solar panels continues to drop, we will likely see a wider adoption. Indeed, the day may come where distributed solar begins to approach central generation prices for energy. As that occurs, Arizona will need to address:

a. The need for generation capacity to back up the energy-only solar systems and regulatory mechanisms to provide cost recovery for such capacity..
b. A reconfiguration of pricing structures to more accurately reflect the costs incurred by different types of customers.
c. Transmission, distribution and system operational issues created by large amounts of intermittent distributed energy.
d. The ongoing need to protect customers and treat all customers fairly.

4. Increasing Federal Control of Transmission

There is continuing federal pressure to impose on the Southwest the system of transmission control that we see in many other parts of the country, notably the Northeast and California. The Federal Energy Regulatory Commission through its Order Number 1000 is applying greater control over regional planning and who pays for transmission through a mandatory cost allocation process. Additionally, there are current efforts to impose on Arizona an energy imbalance market. This is not meant to be a statement critical of these systems, but clearly one size does not fit all. It will be up to Arizona, and other similarly situated states, to develop a cohesive position *that best benefits Arizona*.

5. Slowing Load Growth

With increases in demand side management comes a lower demand for central station generation. We are seeing increased demand side management as a result of more efficient appliances and air conditioners, low energy use lighting and higher building efficiency standards. It is difficult to predict the effect of this reduction in demand growth, particularly in Arizona, but it is a phenomenon that will need to be watched and managed.

6. The Introduction of New Technologies

New technologies will create additional uncertainties. Examples include: the widespread use of electric vehicles and the resultant strain on distribution system; new varieties of distributed generation, including energy storage; and greater use of gas-fueled combined heat and power facilities or microturbines. Arizona will need to manage the energy industry in a way that allows for customers to take advantage of these new technologies while maintaining reliability and our low energy costs.

7. Financing to Keep our Systems Operating

As we move forward it may become increasingly difficult to maintain the financial structures required so that new facilities can be planned, built, and be operational when needed. While this may seem abstract, it is essential for Arizona to maintain and improve the advantages that it has.

So in summary, Arizona must be prepared to manage the changes being brought about by external forces. This means that today, Arizona should be:

- Insuring that pricing structures and systems are fair, while properly incentivizing new industry and economic growth.
- Addressing federal pressure for transmission change to ensure that the systems and timing are right for Arizona.
- Working together to protect Arizona's resources, jobs and economic development activity, and making Arizona attractive to new residents (including retirees) and those who visit our state.
- Watching the resource mix and cost recovery as the electricity demands change
- Anticipating and reacting to new technologies; being prepared to take advantage of them.
- Maintaining local regulatory control of the transmission system instead of ceding control to FERC
- Monitoring the preparedness of utilities to meet expected changes in the demand for electric services.
- Watching carefully to ensure that industry structure and regulatory oversight maintains entities with a vested interest in the success of Arizona.

3. Contrast Arizona's Future with Deregulation

The proposal before the Commission[4] does nothing to address the critical issues facing Arizona. In fact, it moves in the wrong direction for many of them. Experience around the country has demonstrated that retail competition has not delivered on its promise of low cost and benefits to all customer classes and it certainly is not an improvement over Arizona's current system. A move to deregulate Arizona will require wholesale changes in the way utilities operate: who has regulatory jurisdiction, how planning is done (or not done) and how resource decisions are made, and the relationship between local utilities and their customers. Once generation becomes divorced from load the generation owners must act differently. They must consider each action they take in terms of how it will play in the market regardless of the long term impacts. Even if the provision of electric service is only partially deregulated (which SRP believes is not feasible), it will not take long to see our markets move to central control, much as exists in the Northeast.

Here is what would result from current retail competition proposals[5]:

- An elimination of the traditional regulatory compact, which requires a utility to invest in new generation to meet current and forecasted loads, in return for the opportunity to earn a reasonable return on those investments. Future investment and planning would be at significant risk.
- A central control of transmission and the wholesale market (which would in turn be the determinant of retail prices), much like the California ISO.
- A shift of oversight from the Corporation Commission overseeing retail prices to the FERC overseeing wholesale prices.
- A system of "competition" that allows competitive suppliers to cherry-pick the most favorable and profitable customers. This will result in a transfer of costs from large, high-volume users to smaller customers, including residential customers.
- An increased volatility in retail prices, including price spikes during times of high demand.
- A system that leaves to the market the essential responses necessary to accommodate new and different technologies.
- A market where market power or market manipulation on the part of producers must be continually policed. Numerous studies have suggested the continued exercise of market power in RTO-run markets, in spite of FERC's policing efforts.[6]
- A need to oversee a whole new industry of retail marketers, from both in-state and out-of-state, who may not place the interests of Arizona first.

[4] We view the *proposal* as being reflected in the four competitive CC&N applications pending at the Commission. If granted, these applications would resurrect the industry restructuring envisioned in the Commission's 1998 Rules of Retail Electric Competition (R14-2-1601, *et seq.*)

[5] These points are supported by the answers to the eighteen questions and SRP's 2009 position paper.

[6] American Public Power Association. **Consumers in Peril:** Why RTO-Run Electricity Markets Fail to Produce Just and Reasonable Electric Rates; February 2008. p. 2.

- A duplication of costs for billing and customer service functions (and perhaps metering systems) which will increase overall costs without any commensurate benefit.
- A loss in economies of scope and economies of scale; i.e., vertically-integrated utilities produce electricity at lower costs than the combination of separate generation, transmission and distribution functions under deregulation.
- A likelihood of higher costs in the long term. Even if there are *short term* savings as a result of market swings, these are likely to be quite small and not available to all customers.
- A weakening of Arizona's economic development advantage, as energy prices equalize within the Western region.

4. <u>There are no Advantages to Deregulation.</u>

In addition to it being out of step with the times, there is no upside to moving to deregulation:

1. Currently customers in Arizona have a much better deal than most parts of the country:

a. Award winning customer service;
b. Low prices;
c. A wide array of price options and services;
d. Utilities with the financial strength to make new investments needed to serve customers;
e. Widespread adoption of renewable resources by utilities, with benefits made available to all customers;
f. Availability of renewable resources to all customers;
g. Excellent mix of generation resources, both geographically and by fuel source;
h. Excellent integrated planning processes and preparedness; and
i. Stable prices and reliable service.

There is no need to risk these advantages, for the uncertainties of a deregulated market.

2. There is no widespread cry or desire to change the *status quo*. The only noise comes from a very small group of large customers, out of state marketers and generators, who hope to exploit the temporary low prices on the wholesale market, to the detriment of residential and small commercial customers.

3. Once restructuring starts, it is difficult if not impossible to retract to the vertically integrated system. In other words, there is no ability to experiment. Arizona should not make a switch unless the case is compelling.

4. In addition to the substantial start up and maintenance costs, if deregulation is restarted in Arizona, then the utilities will have to again address the issue of payment of stranded costs by customers. Utilities that have built and acquired capacity to serve customers under their regulatory compact are entitled to collect a surcharge to recover the investment that is not recoverable under the new market structure. Also, with stranded cost write-downs comes a decrease in the property tax base.

5. There is now a history of experience with restructured markets in other states and regions. While some may argue that they "work", that conclusion is subject to significant controversy. As these markets develop, reliability and the ability to properly plan deteriorate and costs rise. The costs of forming and operating the necessary market structure are significant and rising. There is little evidence of benefit to retail customers, and much evidence of detriment.

6. A restructured market will experience significant price volatility, it will degrade reliability. Long-term planning will come to an end.

7. The likely losers in a restructured market are the residential and commercial customers, and the State of Arizona.

Conclusion

Even the fact of opening this inquiry is hurting Arizona, creating regulatory uncertainty[7]. The Commission should act quickly to reject the deregulation proposals. This will allow the Commission, along with the utilities committed to Arizona, to move forward with solid plans for the future. Arizona electric customers, those who may move to Arizona, our businesses and our economy rely on our proven electric industry structures.

Deregulation would place Arizona "at the mercy of forces that show no mercy"[8]. SRP recommends that the Commission close this docket.

[7] On June 20, 2013, citing regulatory uncertainty introduced by the Arizona Corporation Commission's review of retail competition, Jefferies LLC downgraded UNS Energy Corp. shares to "hold" from "buy" and decreased its price target to $49.50 from $57.[7] This lack of regulatory certainty has also led Arizona Public Service to further delay its purchase of Southern California Edison's interest in the Four Corners Generating Station, potentially causing issues for APS with the U.S. Environmental Protection Agency.

[8] Former governor Gray Davis of California (about deregulation) http://www.energycentral.com/utilitybusiness/businesscorporate/articles/1591/

Salt River Project

Position Paper

Responses to the Eighteen Questions

Docket No. E-00000W-13-0135

July 15, 2013

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1. Will retail electric competition reduce rates for all classes of customers – residential, small business, large business and industrial classes?

The Commission is sure to receive mixed messages on this question. In reviewing what has occurred in deregulated markets (eliminating the effect of artificially frozen rates) it is difficult to say that customers as a whole, at least in terms of price levels, are better off. There is considerable evidence to suggest that customers in "deregulated" jurisdictions pay a higher price overall.

In an April 2013 study published by the American Public Power Association the differences in prices between regulated and deregulated states were highlighted.[1] The analysis, based on data from the U.S. Energy Information Administration, shows that customers in deregulated states pay on average 3 cents more per kilowatt hour than in regulated states:

Average Revenue per Kilowatt-hour: Deregulated vs. Regulated States

	Deregulated States	Regulated States	National
	(in cents per kilowatt-hour)		
1997	8.6	5.8	6.8
1998	8.3	5.8	6.7
1999	8.1	5.8	6.6
2000	8.4	5.9	6.8
2001	8.9	6.2	7.3
2002	9.0	6.2	7.2
2003	9.1	6.4	7.4
2004	9.2	6.6	7.6
2005	9.7	7.0	8.1
2006	10.8	7.5	8.9
2007	11.3	7.7	9.1
2008	11.8	8.3	9.7
2009	12.0	8.5	9.8
2010	12.1	8.6	9.8
2011	12.0	8.8	9.9
2012	11.9	8.9	9.9

Notes: Deregulated states include: CA,CT,DC,DE,IL,MA,MD,ME,MI,MT,NH,NJ,NY,OH,PA,RI
Regulated states include all other states except for Texas. Texas is included in the National average.

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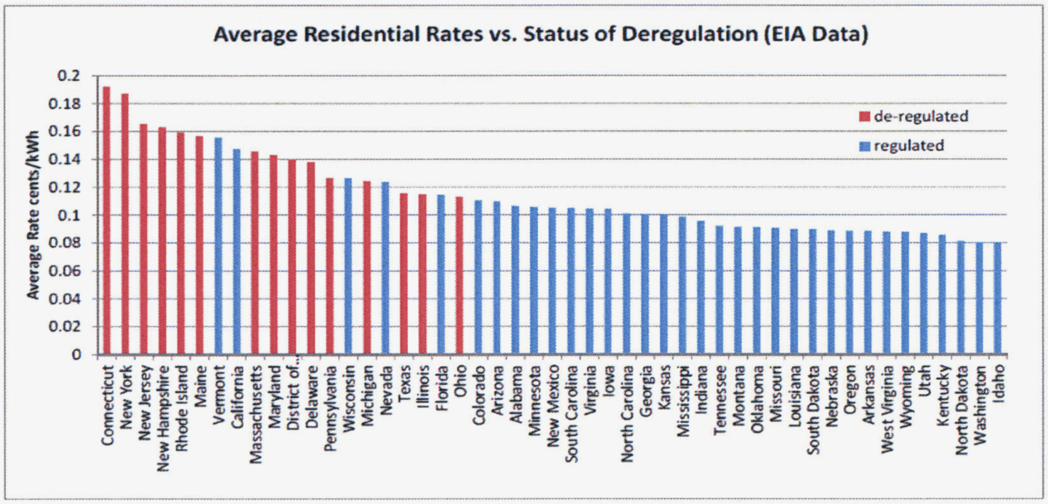
[1] American Public Power Association *Retail Electric Rates in Deregulated and Regulated States, 2012 Update* (April 2013). Available at http://www.publicpower.org/files/PDFs/RKW_Final_-_2012_update.pdf.

Here is a similar graph showing prices state by state.[2]

Figure 1: Average Residential Rates and Status of Deregulation



SRP admits that these statistics may overstate the difference to some extent, as it was the states with very high prices to begin with that chose to experiment with deregulation.

But a report by the Texas Coalition for Affordable Power (TCAP) provides a good example of deregulated prices compared to regulated prices in one state. TCAP looked at prices in the Texas market and compared utility systems that deregulated (the areas served by investor owned utilities) with areas of Texas that chose not to deregulate (mainly the public power entities CPS Energy (San Antonio), Austin Energy and the Lower Colorado River District (Central Texas)).

The increase in prices in the deregulated areas are striking, in comparison to those in the public power areas which did not deregulate. Prices in the deregulated portion during the period from 2002 to 2010 were at times 46% higher than the regulated areas. While prices in the deregulated areas are beginning to drop, proponents can hardly argue that the market produced better prices for Texas consumers than the regulated areas:

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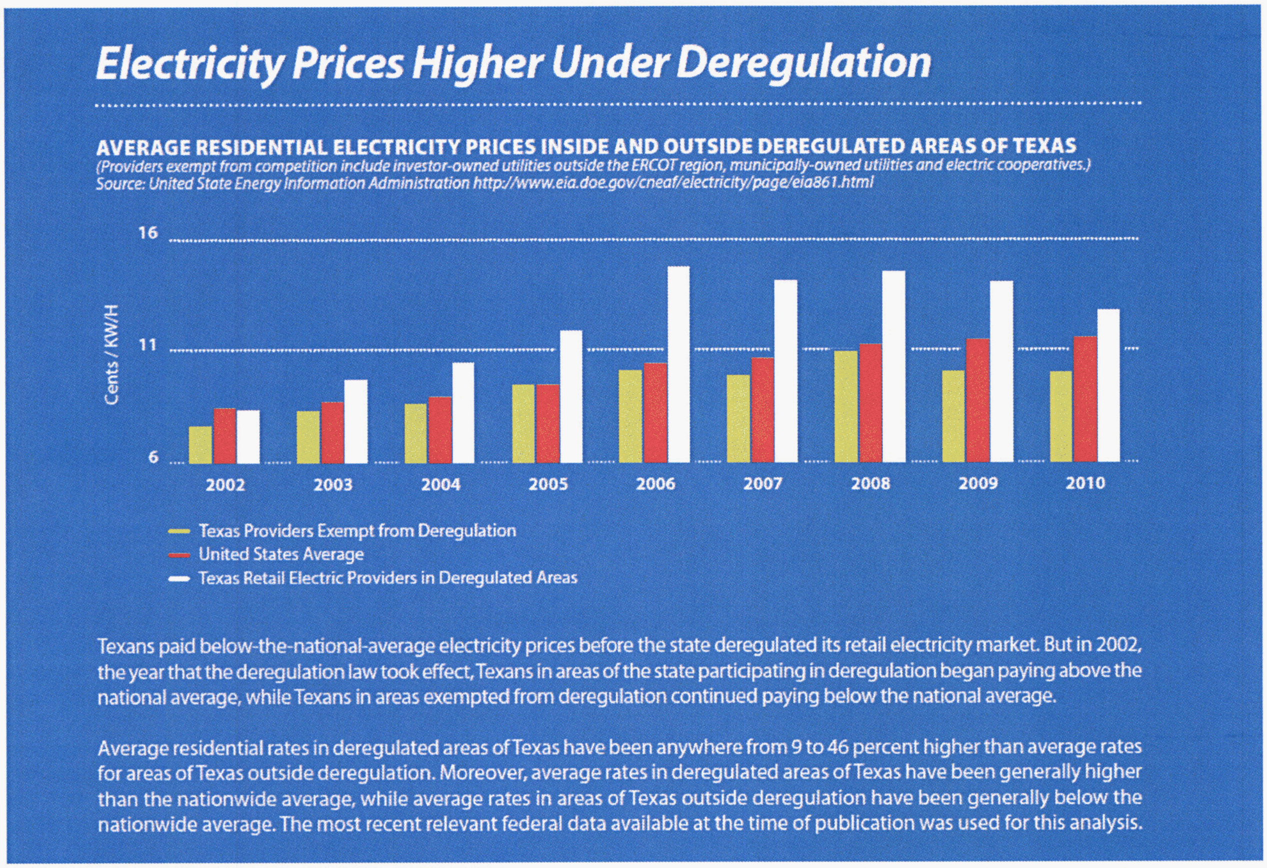
[2] William B. Marcus, JBS Energy, Inc. *Does Deregulation Raise Electric Rates? A Cross Sectional Analysis*, Page 4 (December 2011). Available at http://www.jbsenergy.com/downloads/does_deregulation_raise_electric_rates.pdf.

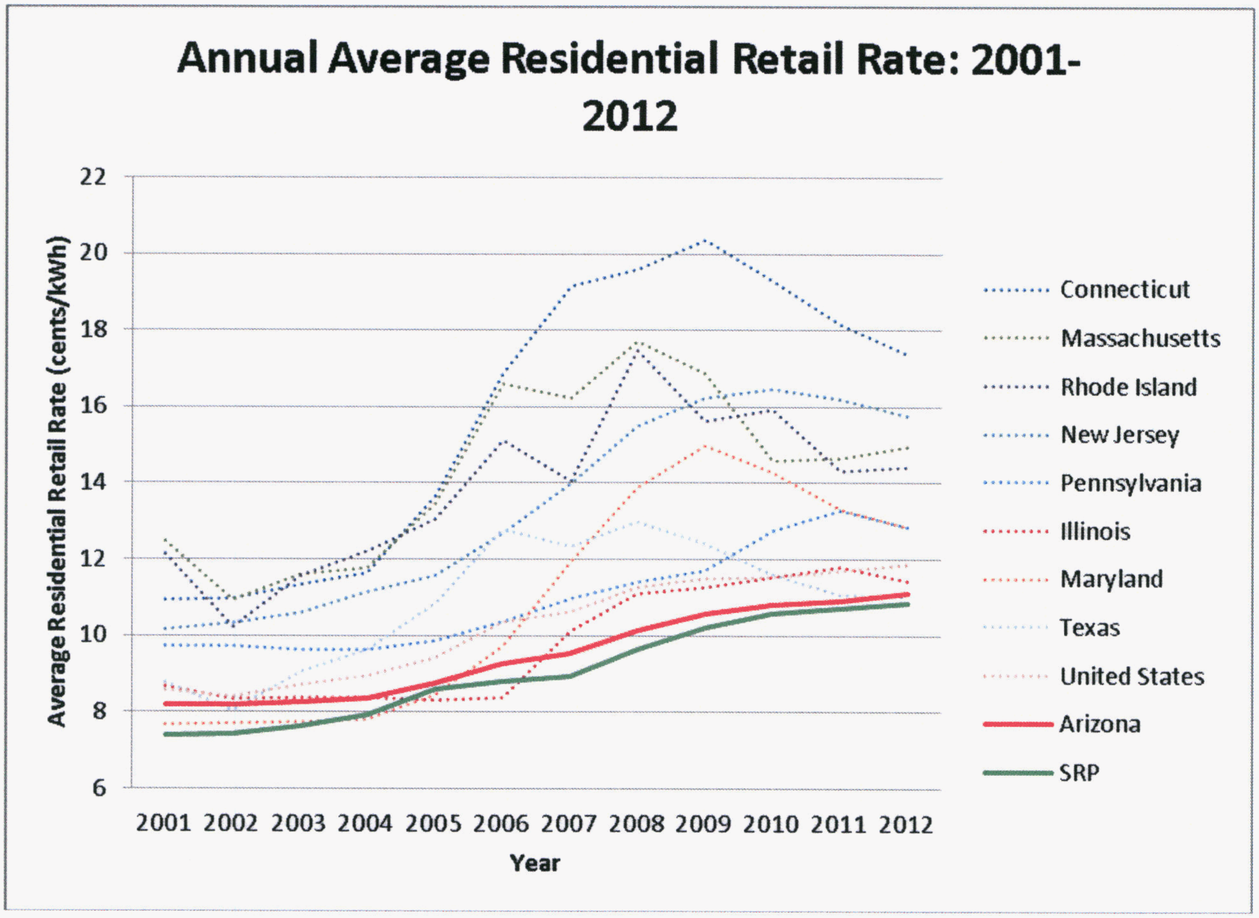


Texas Coalition for Affordable Power *Deregulated Electricity in Texas, A History of Retail Competition*, Page 26 (December 2012). Available at http://tcaptx.com/wp-content/uploads/2013/03/SB7-Report-2012.pdf

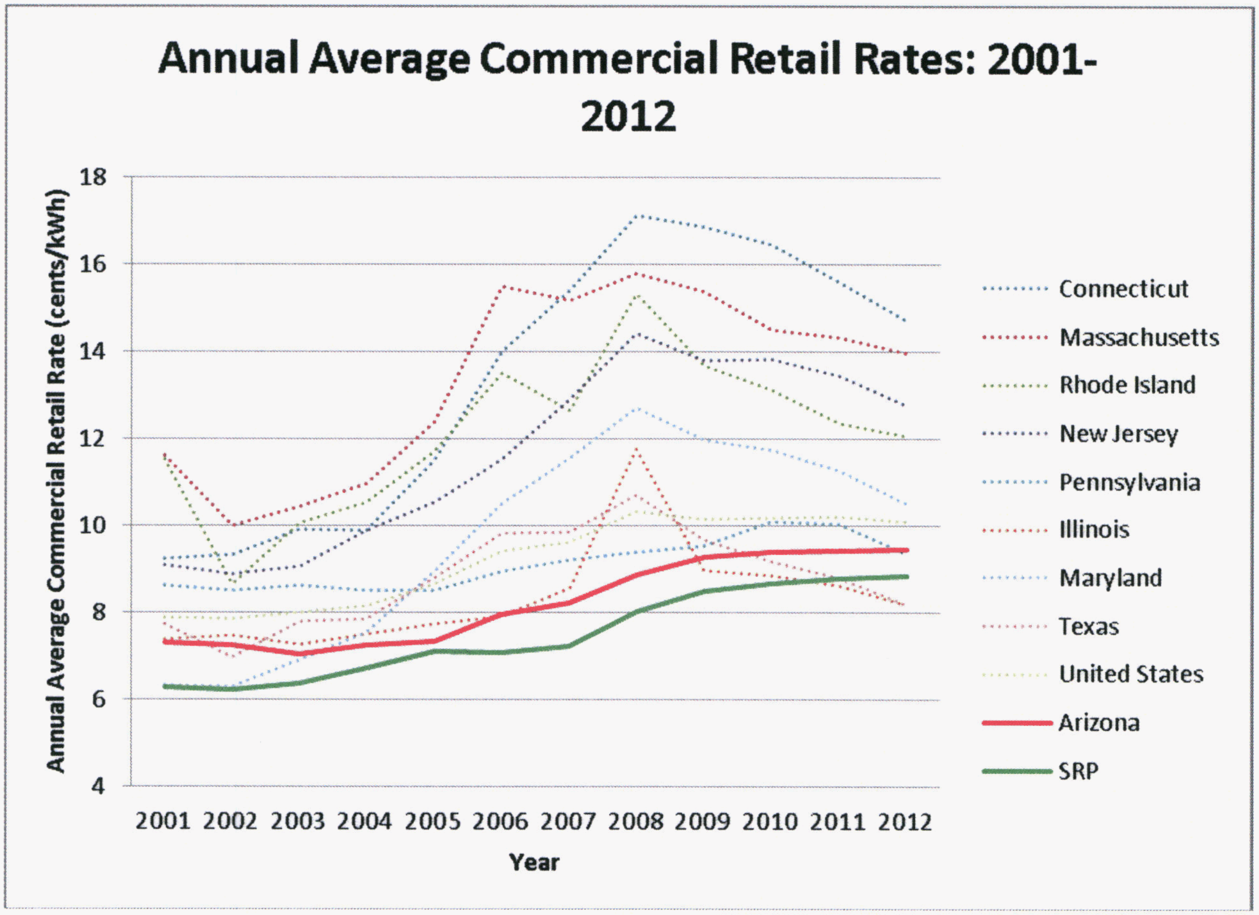
Another way of looking at the question is to examine the differences between prices in deregulated states with prices in Arizona. The following charts are compiled using data from the U.S. Energy Information Administration[3]. In response to the question SRP has separated the data into residential, commercial and industrial categories. In addition to the generally higher prices in the deregulated states, what is interesting here is how closely the prices in some of the states follow the natural gas market prices, a direct reflection on the fact that natural gas plants have proliferated in some of these jurisdictions. These charts also highlight the extreme swings in these markets as compared to the prices in Arizona:

[3] U.S. Energy Information Administration *Average Retail Price of Electricity.* Available at http://www.eia.gov/electricity/data/browser/#/topic/7?agg=0,1&geo=hvvvvvvvvvvvo&endsec=e&freq=Q&start=200101&end=201301&ctype=linechart&ltype=pin&maptype=0&rse=0&pin=

Residential

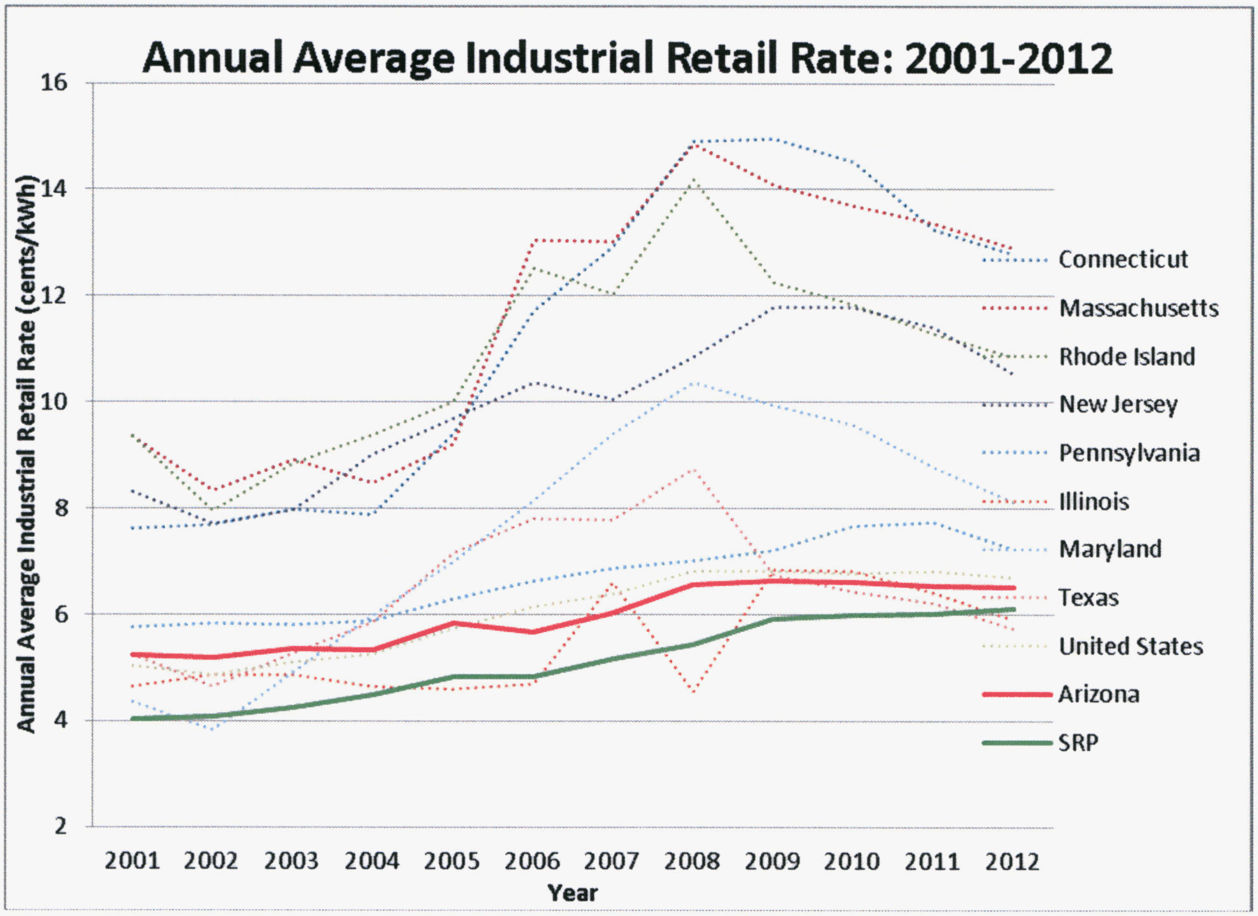


Commercial



Annual Average Commercial Retail Rates: 2001-2012
Annual Average Commercial Retail Rate (cents/kWh)
18
16
14
12
10
8
6
4
2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012
Year
Connecticut
Massachusetts
Rhode Island
New Jersey
Pennsylvania
Illinois
Maryland
Texas
United States
Arizona
SRP

Industrial



Annual Average Industrial Retail Rate: 2001-2012
Annual Average Industrial Retail Rate (cents/kWh)
16
14
12
10
8
6
4
2
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Year
Connecticut
Massachusetts
Rhode Island
New Jersey
Pennsylvania
Illinois
Maryland
Texas
United States
Arizona
SRP

The most recent study attempting to find pricing benefits of deregulation found minimal pricing benefits, about half a cent per kWh.[4] The report also notes retail access states are much more heavily dependent on natural gas fired generation.[5] Heavy dependence on natural gas fired generation can lead to price volatility, as shown by the charts above. Similarly see Seth Blumsack, Lester B. Lave & Jay Apt *Electricity Prices and Costs under Regulation and Restructuring* (2008).
http://web.mit.edu/is08/pdf/Blumsack_Lave_Apt%20Sloan%20paper.pdf

Undoubtedly, the deregulation proponents will cite to the several studies by the "Compete Coalition", particularly the report dated October 19, 2012 entitled *RTO and ISO Markets are Essential to Meeting Our Nation's Economic, Energy and Environmental Challenges.* http://www.competecoalition.com/files/RTO%20White%20Paper%20Updated%20FINAL.pdf. This report concludes that an RTO or ISO structure is "the best way to assure an affordable, efficient and adequate supply of electricity and to meet the nation's current and future energy and environmental needs."

SRP asks that the Commission look carefully at the report. There are a number of flaws in the analysis including:

- The report does not take into account that the states experimenting with deregulation had very high rates to start with. Were the study to compare changes in all states on an apples-to-apples basis, the results would not show the claimed advantages.

- The period that selected for study is critical. By 1997, most competitive retail states had in effect retail rate freezes which masked a lot of the cost increases that occurred after 2005. By including retail rate freeze states in their data, the Compete Coalition skews the percentage increases when looking at this particular period. If we look at the data (for every customer class) there were significant run-ups in retail rates between 2002 and 2007 in the competitive markets that reflect the costs of transitioning to retail competition and stranded investment. If the study had relied on a period that started later than 1997, it would have likely found contrary results.

- Between 1997 and 2011, the inflation-adjusted wellhead price of natural gas decreased by 37%. Because competitive markets are significantly more reliant on gas than regulated markets, they would likely be expected to have had lower percent increases in rates during this period than regulated markets. (Coal prices

[4] Matthew J. Morey & Laurence D. Kirsch, *Retail Rate Impacts of State and Federal Electricity Utility Policies*, Page 19, Christensen Associates Energy Consulting, LLC, February 25, 2013.
[5] *Id.*

continued to rise during this period.) In fact, retail rates decreased only slightly in these markets, even given the significant decrease in gas prices.

- The statistics on growth in retail choice customers is probably explained by the fact that many states have ended regulated provider of last resort (POLR) service, and POLR customers are paying market prices. Thus, to the extent they are switching, they are switching between market choices, not between regulated and market choices.

In conclusion, almost by definition, the effects on various customer classes and types of customers will be disparate. Consider these elements of a market structure:

1. Low prices temporarily available in markets will be limited to short term excess capacity and will be driven by low fuel prices on marginal units. This limited and short term pool of lower costs will be available only to the very large customers who have the flexibility to contract for the capacity on a short-term basis.

2. Marketers will "cherry pick" customers who may be profitable under a competitive market and ignore other customers. These chosen customers may tend to be high load factor customers and customers with strong demand response capabilities. Again this will not be the residential customers.

3. As the cherry-picked customers leave the systems, this will leave greater costs to be picked up by the remaining customers (residential and small business), who will see their prices rise in proportion to the fall in prices to those few large customers.

4. To the extent that stranded costs are not recovered through a non-bypassable surcharge, customers unable to participate in the limited market capacity available will find themselves picking up additional costs left by the departing customers.

5. Unless prices are perfectly unbundled, a daunting task, it is likely that remaining customers will pick up the cost of system reliability, system planning, system reserves, fuel and generation diversity, demand side and renewable costs and related costs.

2. **In addition to the possibility of reduced rates, identify any and all specific benefits of retail electric competition for each customer class.**

Choices and Programs

Proponents of deregulation will argue that customers are given more options. This may have been true in some states in the 1990s. But, it certainly would not be the case in Arizona. Today, SRP offers customers a broad array of options. Customers of other Arizona utilities have similar options. In consultation with its customers, SRP continually updates these options and offers, to better meet customer expectations and needs:

Pricing Options:

E-21: This is an optional super peak TOU price plan. It is known as the EZ3 plan, allowing customers to save money and energy by shifting their usage outside of three peak hours. The three peak timeframes are:
2-5 p.m. Monday through Friday (up to 10,000 participants)
3-6 p.m. Monday through Friday (participation unlimited
4-7 p.m. Monday through Friday (up to 10,000 participants)

E-24: The M-Power plan, which is an optional pre-pay price plan for residential accounts. SRP is the largest provider of pre-pay services in North America.

E-26: This is an optional TOU price plan for residential accounts. Customers can save money by shifting their usage away from peak hours. Peak hours for this plan are:
1-5 p.m. Monday through Friday from May through October
5-9 a.m. and 5-9 p.m. Monday through Friday from November through April

E-28: This is an optional "M-Power" pre-pay time of use price plan for residential accounts.

E-32: An optional time of use price plan for commercial accounts.

E-34: An optional "M-Power" pre-pay price plan for commercial accounts.

E-48: An optional off peak price plan for commercial and municipal pumping accounts.

E-57: An optional plan for unmetered lighting applications including private residences, commercial applications and other lighting applications.

E-61: An optional time of use plan for accounts with a monthly consumption in excess of 300,000 kWh for three consecutive months that are metered at the secondary voltage level.

E-63: A time of use plan for accounts with a monthly consumption in excess of 300,000 kWh for three consecutive months that are metered at the primary voltage level.

E-65: This TOU price plan is for accounts with a monthly consumption in excess of 300,000 kWh for three consecutive months that have dedicated or customer-owned substations.

Available riders to standard price plans:

Economy Price Plan: Qualifying customers with a limited income can receive a $21 discount off each summer billing cycle month and $17 off of each winter billing cycle month.

Medical Life Support Discount: Customers who qualify can receive a $17 monthly discount on their SRP bills while on life-sustaining equipment. A physician must recertify the patient's use of the equipment annually.

Renewable Energy Credit Pilot Rider: This rider allows customers to obtain Renewable Energy Certificates (REC's) from SRP. REC's are associated with energy generated from sources that may include, but are not limited to, solar biomass, landfill gas, wind, geothermal or small hydroelectric.

Buyback Service Rider: This rider allows customers with onsite generation to sell power back to SRP using a market-indexed price, less a transaction fee.

Renewable Net Metering Rider: This rider nets solar generation against a general service customer's total energy usage for systems of 300 kW or less. This rider is intended to encourage installation of solar electricity conversion systems.

Residential Community Solar Pilot Rider: Customers can support solar energy by purchasing a portion of the output generated at a local Arizona solar farm. It's an easy, cost-effective way for customers to support solar without the expense of installing solar panels on their homes.

Business Community Solar Pilot Rider: Customers can support solar energy by purchasing a portion of the output generated at a local Arizona solar farm. It's an easy, cost-effective way for customers to support solar without the expense of installing solar panels on their businesses.

Energy for Education Pilot Rider: This rider is intended to assist schools with replacing or retrofitting equipment so that the schools use less electricity and therefore save on operating costs. Under this limited pilot rider, SRP allows the customer to pay for the capital cost of the equipment over time.

Time-Dependent Demand Riders: These riders, for E-36 and E-47 price plans, allow customers to have the peak demand used in calculation of the demand charge to be based on the highest demand recorded during the on-peak period.

Critical Peak Experimental Price Plan: This plan is supplemental to E-65 and features a reduced on-peak price on "standard" days and a higher on-peak price during peak hours for "critical peak" days.

Standby Electric Service Rider for Power Production Facilities: This rider applies to qualified cogeneration and small power production facilities equal to or greater than 3,000 kW.

Facilities Rider: This rider includes: 1) an average distribution facilities charge for customers taking service from SRP's general distribution system; and 2) a customer-specific charge for substation service.

Use Fee Interruptible Rider: This rider offers credits to customers in exchange for the customer curtailing load.

Instantaneously Interruptible Rider: This rider credits customers for the right to interrupt their load, without notice, for reliability purposes.

Interruptible Rider With 10 Minutes Notice: This rider credits customers for the right to interrupt their load, with ten minute notice, for reliability purposes.

Customized Interruptible Rider: This rider is available to customers who agree to be interrupted at terms and prices not currently available under other programs.

Full Electric Service Requirements Rider: This rider provides a discount for customers with at least 1 MW of load who elect to sign a service contract.

Monthly Energy Index Rider: This rider provides an average monthly energy charge, based on firm market prices at Palo Verde.

Programs:

Budget Billing: SRP Budget Billing™ balances seasonal highs and lows to make payments more predictable.

Custom Due Date: With SRP Custom Due Date™, customers can choose a date between the 1st and 28th of the month to pay their bills.

e-Bill: With SRP e-Bill™ — a paperless, electronic billing option — customers can view statements online anytime and receive email or text notifications when a new bill is ready to be viewed.

e-Chex: The free e-Chex service allows customers to make a payment from a checking account without writing a check.

e-Notes: Through SRP My Account, customers can sign up to receive email or text message alerts for account information, such as bill availability, payment reminders, bill estimates, usage alerts, turn-on confirmations, outage notifications and more.

Mobile Bill Pay: Mobile Bill Pay allows customers to pay their bills by sending a text message from any supported mobile device.

My Account: With SRP My Account™, customers can manage, update and customize their accounts online. They can view and pay their bills, review past energy usage, compare price plans, and view and report outages.

SurePay: With SRP SurePay™ allows customers to authorize their financial institutions to pay their electric bills automatically each month from a checking or savings account.

Home Energy Inspection: SRP offers a Home Energy Inspection for customers who have experienced an unexpected increase in their energy usage. For $55, an auditor will perform a walk-through of the home, providing recommendations on efficiency improvements and ways to conserve energy.

Large-Print Bill: A simplified, large-type version of the regular residential electric bill.

Summary Billing: Business customers with more than one electric account in their names have the option to group their bills. This allows for one payment while still showing billing details for each account.

Outage Reporting and Callbacks: Customers can report power outages online by using My Account, using their mobile devices, calling a Customer Services representative or using the automated telephone system. Customers can request an automated callback after power has been restored.

Outage Tracking/Map: Up-to-date outage and storm information is available online at srpnet.com and within My Account and Mobile My Account. Customers can also get updates on Facebook and Twitter during major storms.

Weatherization Assistance Program (WAP): WAP is a federal program established to help low-income families and individuals improve energy efficiency and lower energy costs while assisting with energy-related health and safety issues in the home. In support of WAP, SRP provides $725,000 per year to the Arizona Community Action Association to assist community agencies in their efforts to improve energy efficiency for SRP low-income homeowners.

Standard Business Solutions: Promotes the purchase of industry-proven, high-efficiency equipment. Rebates are available for qualifying lighting, HVAC, motors and variable frequency drive measures.

Custom Business Solutions: Provides a comprehensive platform for cost-effective non-residential energy efficiency projects such as chillers, process improvements, and energy management systems.

Large Business Solutions: Provides large customers technical service support to identify and quantify energy savings opportunities.

EarthWise Energy Program: This program is for customers who are interested in supporting the development of local renewable resources. Customers voluntarily pay a $3 per-month premium per block to support the EarthWise Energy program.

EarthWise Energy Program for Large Customers This program is similar to the EarthWise Energy Program, but it allows for a discounted payment for EarthWise Energy blocks for large subscriptions.

Renewable Energy Credit (REC) Program: Businesses can support renewable energy by purchasing RECs from SRP. This program allows customers to offset power to their businesses with environmentally friendly wind energy produced in the western U.S.

Rebate and Incentive Programs:

Lighting rebates: $300 per kilowatt of reduced installed demand.

Motors and Variable Speed Drives: $1.50 to $90 per horsepower.

Air Conditioner Retrofit: $200-400 per unit on residential and $20 to $85 per ton on business installations.

Custom Energy Efficiency: $0.11/annual kwh savings - first year up to 50% of the incremental cost.

Compressed Air: $0.80 up to $1.50 per standard cubic foot per minute.

Power Partners - Demand Response: EnerNOC 20-30 MW; began FY2010.

Compact Fluorescent Lighting: Discounts at participating retailers.

Appliance Recycling: $50 and pick up of working refrigerators for recycling.

$99 Complete Home Energy Check Up: SRP's Home Performance with Energy Star program evaluates residences and identified ways to make it more energy efficient. It's a $500 value.

Shade Tree Rebate: $50 for planting desert adapted trees in energy saving locations.

Air Duct and Test Repair Rebate: Up to $75 towards testing and up to $175 for repairs.

Energy Efficient Pool Pump: Up to $150 on a variable speed pump.

Solar Electric Program (Rooftop): SRP provides incentives to residential customers for installing solar electric systems on their homes.

Commercial Solar Electric Program: SRP offers business customers the option of production-based or one-time incentives to make rooftop photovoltaic systems at their facilities more affordable.

Solar Water Heating Program: Business and Residential customers can receive incentives from SRP for installing solar water heaters in their businesses or homes.

Services:

Reaching SRP: Customers can contact SRP by phone- 24 hours per day, by email, or online.

PayCenters: Customers can pay their bills or make SRP M-Power® purchases at over 90 locations throughout the Phoenix Metropolitan area. All transactions are free of charge.

Online Order Requests for Residential Customers: Customers can request duplicates of monthly bills and changes to their electric accounts online, including service start, transfer and cancellations.

Safety Net: Customers may ask to have a friend or family member receive copies of reminder notices when their bills become past due.

Resource Counselors: SRP resource counselors work with customers who have trouble paying their electric bills. They can provide contact information for community partners who may be able to offer more extensive help.

SHARE Program: SRP has teamed up with other state utilities, area utility customers and The Salvation Army to provide financial assistance to those in need.

Alternative Dispute Resolution: SRP ombudsmen work with customers and the public to arbitrate and mediate unresolved SRP service- related power and water disputes.

Energy-Efficiency Financing: National Bank of Arizona is offering qualifying SRP residential (and small-business) customers low, fixed-rate financing for energy-saving projects. This third-party financial institution provides the offer to help SRP customers pay the upfront costs of larger energy-efficiency projects.

While advocates of deregulation may claim to offer new products and services, it is a fact that the current system produces a vast array of new services without the risks or transition costs associated with deregulation. It is hard to see that there is a great deal of room for improvement.

Research

SRP is on the cutting edge of seeking and deploying new technologies and programs. Some examples of the innovative work we are doing with ASU are detailed below:

- Energy Storage – at ASU Polytechnic
  For energy storage to be considered a viable option in the Phoenix area, understanding the effects of the local climate on batteries is essential. This project enables a better understanding of those effects and allows SRP to determine the performance, life and costs of energy storage in Arizona. This research will evaluate

the performance and reliability of various battery types, using different battery chemistry, at different temperatures, assessing whether climate controlled environments are needed or justified for energy storage devices. The project has also constructed a large device that will evaluate battery health.

- Power Plant Efficiency - at ASU Fulton School of Engineering
  The steam turbines Unit 7 of the Kyrene Generating Station are delivering less-than-expected power output. Even a small fraction of improvement in efficiency can translate to vast differences in operational costs over the long term. This project will develop a system to access the steam conditions of the turbines and will ultimately identify possible causes of efficiency degradation.

- Distribution System Reliability - at ASU Fulton School of Engineering
  The project is designed to evaluate historical loading of SRP's 69kV cables, determine whether thermal stress has caused loss of life, and perform a risk assessment of theoretical single contingency. The project has obtained critical outage and transfer factors from transmission planning and used these to simulate existing SRP projects, compare with historical ratings, and determine maximum exposed temperatures. Upcoming tasks include continuation of estimated cable loss of life, construction of a software application to guide transmission dispatchers regarding cable loading during system emergencies, and completion of the final report.

- Long-term Reliability of Solar Photovoltaic Systems - at ASU Polytechnic
  As PV system installations continue to rise, measuring and predicting their performance, reliability and availability have become more important to installers, integrators, investors, and owners. Monitoring and analyzing the performance degradation and reliability of existing PV systems is essential to predicting the same aspects of future systems. This project will evaluate the performance, reliability, and availability of a number of solar PV systems that SRP owns or maintains, conducting field inspections and performance tests on these systems, analyzing the array performance over time, and providing a current reliability assessment.

- Power Plant Water Quality - at ASU Polytechnic
  Current and future water quality standards dictating nutrient and metals limits pose a significant challenge to power plant cooling water discharge. The objectives of this project are to identify the contaminants of greatest significance in relation to current and future water quality standards; select those contaminants for further study for algae bioremediation; identify and select algae strains to reduce the concentration of the identified nutrients/metals; perform laboratory and small scale outdoor testing at Santan Generating Station to determine the ability of the chosen algae strains to remove targeted contaminants; and to determine possible uses of resultant algae biomass based on nutrient and metal composition.

Awards

Proponents of deregulation may argue that customers will get better service in a deregulated market. It is hard to imagine this in Arizona. SRP is nationally recognized for its commitment to customers and its levels of customer service.

In fact, tomorrow J.D. Power will announce that SRP has been awarded its **twentieth straight** award for residential customer satisfaction. This year SRP is rated number one in the West and number one nationally among large utilities.[6] In 2012, SRP was honored with J.D. Power's highly coveted Service Excellence Award (SRP was singled out from 800 brands across industry, not just across utilities, including for example airlines, car manufacturers and hotels). SRP's call centers have received the prestigious J.D. Power

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[6] Since 1999 SRP received these awards:

J.D. Power Residential Service

*1999 - SRP first in the West
*2000 - SRP first in the West (first in the nation)
*2001 - SRP second in the West (one point behind TEP)
*2002 - SRP first in the West
*2003 - SRP first in the West
*2004 - SRP first in the West (first in the nation)
*2005 - SRP first in the West
*2006 - SRP first in the West (first in the nation)
*2007 - SRP first in the West
*2008 - SRP first in the West (second in the nation)
*2009 - SRP first in the West
*2010 – SRP first in the West (second in the nation)
*2011 – SRP first in the West (third in the nation)
*2012 – SRP first in the West (third in the nation)

J.D. Power Business Service

The business study was expanded in 2004 to include utilities like Salt River Project. Since that time:

*2004 - SRP first in the West (first in the nation)
*2005 - SRP first in the West
*2006 - SRP first in the West
*2007 - SRP fourth in the West (tenth in the nation)
*2008 - SRP third in the West (tenth in the nation)
*2009 – SRP second in the West
*2010 – SRP first in the West (ninth in the nation)
*2011 – SRP first in the West (first in the nation)
*2012 – SRP first in the West (first in the nation)

Contact Center Certification for the past seven years. Other utilities in Arizona have received similar awards.

Complaints and penalties in deregulated markets

While there are some companies in these deregulated markets with good service, overall the record of complaints and penalties raises serious concerns about consumer benefits. For example, in Texas during the period from January 2011 through August 2012, the Public Utilities Commission assessed over $3,788,060 in penalties to electric market participants. The following table provides a summary of electric industry Notices of Violation since January 2011. During 2011 and 2012, Commission Staff opened 166 investigations for the electric industry and closed 104 investigations.

Table 1 - Notices of Violations

Violation Type	Penalty Amount
Retail Market Violations	$2,350,200.00
Service Quality Violations	$985,860.00
Wholesale Market Violations	$452,000.00
TOTAL	**$3,788,060.00**

In addition to the administrative penalties assessed, in 24 cases the Commission also revoked or suspended, or the retail electric operator relinquished its certificate to operate. Table 2 below provides a breakdown of the number of certificates revoked, relinquished, or suspended.

Table 2 - Certificates Revoked, Relinquished or Suspended

Type	Number
Number of Certificates Revoked	8
Number of Certificates Relinquished	15
Number of Certificates Suspended	1

Source: Public Utility Commission of Texas, *Report to the 83rd Texas Legislature, Scope of Competition in Electric Markets in Texas*, Page 15 (January 2013) http://www.puc.texas.gov/industry/electric/reports/scope/2013/2013scope_elec.pdf

3. How can the benefits of competition apply to all customer classes equally or equitably?

By its nature, the benefits (to the extent that there are any) of competition will not apply equally or equitably to all customers. There will be winners and losers among customer classes and individual customers. Those customers with the lowest cost of service and the best demand profile, mostly industrial and large commercial customers, will get the best rates. Customers who cost more to serve or have less desirable demand profiles, mostly residential customers, will pay more. That is the nature of competition.

The issue of ensuring equitable benefits is an issue of constant dispute, deliberation, and re-regulation at the regulatory commissions in all the deregulated states. For example, Pennsylvania recently initiated a proceeding to increase residential and small commercial customer use of alternative suppliers, regulating how many customers can take service from such providers and specifying a discounted rate for participating customers.[7]

States in restructured markets are not considering how to increase competition, but rather are looking at how to re-regulate to deal with the problems of deregulation and restructured markets. For example, the whole construct of "capacity markets" being furiously discussed in RTO areas is a regulatory response to a problem that has developed: no one is building new capacity in those markets.

Arizona utilities already ensure that the benefits of competition apply to all customer classes equally and equitably. Both on a long-term, daily, and hourly basis, dedicated Arizona utilities look for opportunities in the wholesale market for buying power that is cheaper than its own production units. When these opportunities are identified, the cost savings accrue to all customers.

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[7] In April 2011, the Pennsylvania PUC initiated an investigation into the state's competitive retail electric markets, and on March 1, 2012, the PUC issued a Phase 1 order, which included details regarding default service plan time periods, energy contract durations, retail opt-in auctions, referral programs, time-of-use rates, default service rate adjustment structure, and hourly priced default service. As part of the 2013-2015 default service plans, the PUC approved two "retail market enhancement" measures aimed at increasing competitive supplier options for residential and small commercial customers, with discounted rates for four months, and bonuses ($50) given to customers that remain on the program longer than four months. Customer participation in the program is limited to 50% of the customers in a given customer class, and individual suppliers may not account for more than 50% of the load served under the program. Final Order on Intermediate Work Plan (Phase 1)(Docket No. I-2011-237952). Available at http://www.puc.state.pa.us/pcdocs/1167521.docx. *See also* February 14, 2013 Final Order at 12. Investigation of Pennsylvania's Retail Electricity Market. Docket No. I-2011-237952; More information is available at http://www.puc.state.pa.us/utility_industry/electricity/retail_markets_investigation.aspx

Deregulation would have the opposite effect. It would allow only certain customers (probably large, high load factor customers) to take advantage of lower cost deals, leaving other customers with the burden of higher costs. Currently, regulation is the only mechanism that can ensure that cost savings from wholesale competition inure to the benefit of all retail customers.

4. Please identify the risks of retail electric competition to residential ratepayers and to the other customer classes. What entity, if any, would be the provider of last resort?

The Risks

As SRP explained in its 2009 position paper (attached to this position paper), when regulation is lifted significant risks emerge:

1. <u>Little Upside, Much Downside Risk</u>

Though there are always claims of how deregulation will lower costs and unleash new value for consumers, there has been scarce evidence that this has occurred in deregulated states. The historical reality is such benefits have occurred in regulated environments because of technology improvements that increased the efficiencies of generating facilities or that lowered the cost of fuel. What we have seen as regulations were removed is that potential "competitive" providers look to exploit the seams in system by cherry picking select customers. The result is a shift in costs from one group to another, not any real benefit to the system as a whole.

On the other side, downside risks are huge. The systems needed to manage these new markets and integrate with the complex and dynamic electric delivery system are hugely expensive. Mistakes have costly ramifications, as the experience in California demonstrated all too clearly. Most certainly prices will rise as new costs are injected into the system (e.g. the cost of risk capital and the cost of infrastructure for new participants). But more importantly, when participants' risks and responsibilities are separated from those associated with maintaining the integrity and economics of the system as a whole, there is no assurance that electricity will always be available, at any price.

2. <u>Increased Risks Reflected in Costs</u>

Many advocates of deregulation point to the shifting of risk away from the customer and to the producer or retail supplier as a primary benefit of restructuring. Such assertions are attractive on the surface, but ignore the reality of how risk is reflected in costs. No power supplier will risk hundreds of millions of dollars in new generation unless it is fairly certain of a large reward, certainly greater than the return provided in a regulated environment where there is less risk to the supplier. Thus, almost by definition, the shift of risk from customers to suppliers in competitive markets results in higher required returns. Thus far, experience has shown no one sees expected returns that are high enough to invest in new central-station generation, and accordingly none is being built in the centrally organized markets. In an industry where decisions on building must be made years in advance, this development is very troubling to many in the industry.

The bottom line is that the only way that suppliers in deregulated markets will assume more risks than regulated suppliers in organized markets is if they are assured of higher returns to reflect that risk. In either case, customers will pay the risk-adjusted returns necessary to meet their needs.

3. Inability to Attract Capital to New Projects

In order to attract capital, financial markets demand some assurance of the ability to repay the investment, namely a future demand for the product. In a deregulated market, there is no assurance of future demand for generation, because there is the possibility of multiple market entrants, especially given the lead times required to develop new generation facilities. The result is that plants are not built without a long term contract with a credit worthy retail provider. Generators in restructured markets have been unwilling to sign long-term contracts, believing they can fare better relying on the volatility in the short-term markets. Thus, plants will only be built to service the remaining load of the distribution utilities (if they can make long-term service commitments – an open question) or not at all leading to a scarcity of generation resources and price increases for consumers.

4. Unacceptable Retail Price Fluctuations

Marginal cost pricing sounded promising when it looked like the marginal cost of new generation would be lower than the average cost of existing generation. The reality is that the equation quickly flipped after the initiation of organized markets in other areas of the country, exposing consumers to higher prices than traditional cost based pricing in addition to extreme price volatility. There may be a short-term reversal again now because of the over-supply of natural gas, but that is not expected to last as gas consumption rapidly rises and pipeline constraints come into play. Over the long-term, one cannot expect short-term marginal prices to continue to be lower than long-term regulated prices.

Moreover, because electricity is a good that is essential to life and business, it is highly price inelastic. It is thus unacceptable to leave retail electricity prices to an unregulated market. As we have seen time and time again in the deregulated markets, the result will be increased regulation, either through price caps, artificial capacity markets, attempts on the part of states to build subsidized generation, or attempts to re-regulate and vertically re-integrate utilities.

5. Market Power and Manipulation

If California taught us anything, it is that an unregulated market for an essential and inelastic good creates opportunities for criminal behavior and the efforts to monitor and manage against such behavior creates expensive new layers of bureaucracy. In the response to question 5, SRP provides additional and current examples of market power and manipulation in deregulated environments.

6. Risk of Customer Complaints

Evidence from Texas suggests that choices have increased, but so has customer dissatisfaction. The Texas Coalition for Affordable Power notes that, "Electricity related complaints averaged around 1,300 each year prior to implementation of the deregulation law to as much as 17,250 under deregulation. The most common complaint relates to billing, although discontinuance and provision of service complaints also rank high."[8]

7. Provider of Last Resort

Initiating deregulation means that the regulatory compact is broken; utilities cannot be expected to have an obligation to invest in capacity for a customer load that may come and go as they please. Thus, establishing and funding a provider of last resort (POLR), or otherwise dealing with customers who don't choose or cannot obtain an alternative supplier is mandatory in a deregulated market.[9]

The POLR is the utility that assures that adequate system capacity is available to serve its entire retail load, even as load is changing constantly as customers leave for competitive providers and come back to the POLR provider. It is the POLR that assures that that there is sufficient capacity to meet the POLR load, either by maintaining its own capacity or by purchasing sufficient energy in the market. In many cases, the POLR supplier issues competitive bids for others to satisfy the hourly needs of the POLR customers. In other cases, the POLR provider offers a standard service to POLR customers, and must maintain (or purchase) the capability to provide that service.

In any case, long-term planning for POLR service is made impossible due to the fact that the POLR provider does not know from one year to the next (or even one month to the next) what its load is expected to be. If the POLR provides a standard offer price, it becomes the "price to beat" for competitive suppliers. When market prices are lower than the "price to beat", customers will leave. When it's higher, customer will come back. Some states have had to limit the number of times customers can choose alternative suppliers to lessen the effects of this customer movement.

So given that the POLR cannot forecast demand, what happens? Well the difficulties being experienced in the organized markets can really be traced back to this significant

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[8] Deregulated Electricity in Texas: A History of Retail Competition (December 2012) Texas Coalition for Affordable Power, page 75; available at http://tcaptx.com/wp-content/uploads/2013/03/SB7-Report-2012.pdf.

[9] The one exception is the ERCOT portion of Texas, where the Texas legislature decided that all customers would be required to choose an alternative supplier when the market was deregulated.

shortcoming in competitive markets. If no one has an obligation to serve, who assures that reliability will be maintained? The organized markets were fortunate to not have to deal with this question immediately, as for a long time there was excess capacity in these markets. But the tide has changed, and a clearly a problem has emerged. RTOs are looking to capacity markets as a way to address the problem, but no one is sure yet that they will work, and at best they are dealing with capacity only three years into the future. No one is likely to build substantial capacity based on a three-year assurance. We may yet see re-regulation of these markets and re-institutionalization of some kind of service obligation.

An alternative might be to try to retain a service obligation on the part of the current retail suppliers in Arizona as the State moves to deregulation. This would be an extremely costly option, and it's unclear who would pay the bill. Without knowing exactly how many of their customers might depart, SRP and other retail suppliers would have to build and maintain enough capacity to serve their entire load. There would be fewer customers to bear these costs, and adding these burdens to those customers would cause even more of them to leave, resulting in a death spiral for Arizona utilities. And there would be substantial duplication of generating facilities. It is a lose-lose proposition both for the bulk of utility customers and for the utility.

In the Sempra CC&N docket on August 31, 2007 (Docket No. E-03964A-06-0168) SRP and New West Energy sponsored the prefiled testimony of Frank Graves of the Brattle Group, which particularly addresses the essential importance of providing POLR service in a restructured market. Dr. Graves points out that Arizona does not have in place a system that in any respect can be considered adequate:

> [The lack of adequate POLR service] has impeded the development of a pool of competitive ESPs, and in some cases it has imposed large, uncompensated financial risks on utilities providing the service. For SOS [Standard Offer Service] to avoid these pitfalls, all the major elements of its design must be carefully and consistently specified, including customer class differentiation, switching rights, term (horizon), pricing rules, procurement mechanisms, and regulatory approval guidelines. This has not yet happened in Arizona. In particular, existing generation tariffs were not developed with the intent or effect of compensating the utilities for the costly risks associated with customer switching. Thus, these prices do not provide a fair or efficient SOS price for prodigal ESP customers.

Graves Testimony, p. 5:1-11.

Dr. Graves totally dispels the idea that Arizona has already addressed the issue:

> POLR is a different, more complicated service than simply serving franchise customers with embedded generation, and its design, pricing, and procurement mechanism need to be specified in advance of allowing ESPs to begin serving customers. This has not yet happened in Arizona. Instead, the existing tariffs for generation service are being described as if they are the POLR service.

Graves Testimony, p. 11:6-11.

Dr. Graves explains that the Arizona system is inadequate:

> At present in Arizona, the tariffed rates for utility customers [purport to provide POLR protection], but those rates were not set with the intent or effect of compensating the utilities for bearing customer-switching risks. As discussed above, the required premiums can be significant. Instead, these are cost-of-service rates set to reflect generation accounting costs and a fair return on the underlying assets in a non-switching environment. If/when ESP customers switchback to this utility service, that can only occur at the expense of utility financial losses or increased costs to other customers who did not switch. Both outcomes are unfair and inefficient. Thus, these tariffed services should not provide comfort to the ACC about the just-and-reasonableness of ESPs' proposed maximum prices.

Graves Testimony, p. 17:18-23.[10]

Dr. Graves concludes:

> To my knowledge, virtually none of the several prerequisite steps involved in retail market design have yet transpired in Arizona: As a result, customer classes may have constituents with extremely different marginal costs, making them prone to cherry picking. The current generation services from utilities were not crafted or priced with POLR risks in mind, so they do not provide a suitable backstop service. Questions about how

[10] Note that the provider of last resort obligation does not exist at all for customers of public power entities who use more than 100,000 kWh per year. A.R.S. § 30-806(I).

> much risk to include in the price of POLR (e.g., some degree of real-time pricing) have not been debated, and the tension between Integrated Resource Planning and customer choice has not been fully recognized. The enabling legislation and law seems to require a review of ESP tariffs and profitability that is not well-defined and which could be counterproductive. Criteria for monitoring and evaluating the performance of retail market competition are not in place.
>
> In short, there seem to be many aspects of this complex problem that have not yet been adequately considered. . . . Perhaps there is a lack of awareness of these issues, or perhaps there is a presumption that they were all well-vetted initially and we have simply been waiting for a more auspicious time to apply those prior insights. I would suggest that that is unlikely, given how much we have learned in other settings about the difficulties in getting retail access to work well. Failure to address these prerequisites before opening the doors to retail choice is likely to result in Arizona repeating the mistakes of others.

Graves Testimony, pp. 29:10 – 30:4

It is undetermined whether a "competitive" market can co-exist with a true provider of last resort responsibility. Certainly the concept has yet to be proven, and all evidence and the recent actions of deregulated markets, points to the contrary.

5. **How can the ACC "guarantee" that there will be no market structure abuses and/or market manipulation in the transition to and the implementation of retail electric competition?**

There is no guarantee from anyone. And certainly this Commission cannot provide guarantees, as the pricing will largely be set by wholesale markets which will be primarily subject to federal, not state regulation.

There has been increased regulation and oversight at the federal level since the Enron days. But, even today we continue to see allegations and admissions of major market manipulation:

- In 2012 FERC provisionally fined Barclays Bank a total of $435 million and ordered the bank to repay $34.9 million in "unjust profits" as it accused the lender of engaging in a "coordinated scheme to manipulate trading at four electricity trading points in the Western United States".
- On November 19, 2012, FERC approved a stipulation and settlement agreement with Gila River Power, LLC, in which Gila River admitted to manipulating the California ISO electric market by arranging nonexistent wheeling transactions to artificially reduce congestion on an interface used as a critical import path to the CAISO market. FERC concluded that this behavior violated FERC's prohibition on electric market manipulation and the prohibitions on the submission of inaccurate information in electric marketing activities in FERC's market-based tariff regulations and the CAISO tariff.
- On March 9, 2012, FERC approved a stipulation and consent agreement between FERC's Office of Enforcement and Constellation Energy Commodities Group. As set forth in the settlement, CCG agreed to pay a civil penalty of $135 million and to disgorge profits of $110 million, plus interest, to resolve an ongoing investigation into allegations that CCG violated FERC's prohibition of electric energy market manipulation.
- On January 11, 2012, FERC issued an order approving a settlement relating to allegations that a Senior Vice President of North America Power Partners engaged in fraudulent conduct in violation of FERC's prohibition against market manipulation and committed violations of the PJM Interconnection, LLC's (PJM's) Open Access Transmission Tariff.
- On November 29, 2011, FERC approved a stipulation and consent agreement between the Office of Enforcement and Holyoke Gas and Electric Department in which Holyoke stipulated that it failed to report to ISO New England, Inc. three

planned outages of two of its generating units serving as ISO-NE capacity resources, as required under the ISO-NE tariff.

- On October 28, 2010, FERC issued an order approving a $2.7 million settlement relating to allegations that North America Power Partners engaged in fraudulent conduct in violation of FERC's prohibition against market manipulation and committed multiple violations of the PJM Interconnection, LLC's Open Access Transmission Tariff.

Another problem stems from market power in organized markets that may allow certain generators to influence the market price they are paid. Because many generators are located in areas constrained by transmission, the prices they charge must continue to be regulated. Normally, market monitors in each of the RTOs are responsible for determining who has market power and how that market power must be mitigated. FERC would get involved if there are any disagreements.

Thus, in many regions, quite a bit of generation continues to be regulated even after deregulation, but by federal regulators. Furthermore, FERC must constantly monitor whether generators have acquired market power through consolidation, retirements of generation, or other changes in the market. While markets rely on FERC to police the market, it is usually only after the fact that they are able to catch violators. And every time there are price spikes in the market, accusations of manipulation or exercise of market power have to be investigated by FERC. In addition, the difference between prices resulting from market power and prices resulting from real market scarcity are extremely difficult to differentiate. It is an imperfect system at best, but one of the great ironies of deregulation is that it often requires even more regulation. An even greater irony is that under deregulation the increased federal authority would come at the cost of state control.

6. **What, if any, features, entities or mechanisms must be in place in order for there to be an effective and efficient market structure for retail electric competition? How long would it take to implement these features, entities, or mechanisms?**

The eleven states, the majority of Texas, and the District of Columbia,[11] that have restructured for all retail customers, are continually working to fix the flaws in their markets. For example, in addition to the ongoing investigation in Pennsylvania and the capacity issues in Texas (see response to question 9 below), there are ongoing activities in both Maryland and New Jersey attempting to provide financial support for new generation, with customers subsidizing the costs of such generation. In both states, there is too much congestion on the power grid and not enough capacity, leading to high electricity prices for customers. And even with higher prices, significant new capacity is not getting built. These states have chosen to implement a mechanism beyond price signals in an attempt to more reliably ensure resource adequacy and protect ratepayers.[12]

Moreover, arbitrage opportunities will exist within any market structure. Experience with California's foray into deregulation indicates that features or mechanisms to protect consumers, no matter how well thought-out, can be gamed by market participants. While FERC now has the ability to impose significant fines and has considerably expanded its Office of Enforcement, market manipulation is an ongoing issue as evidenced by FERC's recent market manipulation enforcement actions against JP Morgan and Barclays.[13]

That being said, the minimum elements of a competitive retail market consist of an independent centralized structure to run a wholesale market and operate the system, a complete unbundling of retail services and prices, and an assignment, financing, and cost recovery mechanism for a true POLR function. In most cases where centralized markets were adopted, there were pre-existing organizations that carried some or most of the

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[11] Connecticut, Maine, Massachusetts, Rhode Island, New Jersey, New York, Pennsylvania, Illinois, Ohio, Delaware, the District of Columbia, and the majority of Texas are full restructured, with retail access for all customers. Montana, Oregon, Washington, Nevada, Michigan, Virginia, and New Hampshire have a limited on direct access, limited to certain classes or sizes of customers or limited by a certain amount of a utility's retail sales.

[12] Synapse Energy Economic *Incenting the Old, Preventing the New: Flaws in Capacity Market Design and Recommendations for Improvement* (June 14, 2011). Available at http://www.publicpower.org/files/PDFs/2011APPACapacityMarketsReport.pdf; Tom Johnson NJSpotlight *In Search of New Generation, MD's Struggles Mirror NJ's* (April 13, 2012). Available at http://www.njspotlight.com/stories/12/0412/2016/

[13] *JP Morgan loses California power sale fight at U.S. FERC* (June 10, 2013). Available at http://www.reuters.com/article/2013/06/10/jpmorgan-ferc-idUSL2N0EM0U020130610; *see* also FERC Docket No. EL12-103-000; Brian Wingfield (January 29, 2013). Available at http://www.bloomberg.com/news/2013-01-29/ferc-staff-backs-penalties-for-barclays-in-energy-probe.html; *see* also FERC Docket No. IN08-8-000

functions of the RTO. Such is not the case in Arizona. There are also questions about whether an Arizona only market would work and meet FERC's requirements, and the involvement of other states and utilities would be a complicating factor. Arizona would have to make decisions about whether or not any generation needs to be divested, how it would be divested, and stranded cost recovery. Rules would have to be established for customer switching. Regulations governing consumer practices of new retail providers would need to be developed. Proceedings to establish all of these rules and regulations would probably take five years, if not more.

7. **Will retail electric competition require the divestiture of generation assets by regulated electric utilities? How would FERC regulation of these facilities be affected?**

Divestiture was a concept developed in the 1990s to ensure the disaggregation of the industry; that is to break up the vertically integrated utilities. The idea behind divestiture is that too few suppliers in a market would give any one of them the ability to profitably raise the market price for their output for a significant period of time. But, there is no *per se* requirement that generation must be divested in a competitive generation market. In fact there are indications that divestiture reduces the ability of the market to hedge against market price volatility, causing significant price swings in deregulated states. And once divestiture occurs, it cannot be reversed.

More importantly, divested generation cannot be claimed for the sole use and benefit of Arizona consumers. Additionally the divestiture of generation will tend to accelerate the need to establish central markets run by RTOs. Under divestiture, generators that traditionally provided essential cost-based reliability services in Arizona, such as must-run service, regulation or spinning reserves will be repurposed to maximize profits in the regional wholesale market. Under this model, RTO's must be established with the responsibility to provide the services previously provided by the vertically integrated utility.

Finally as central markets develop the function of regulation of rates will shift to the regulation of wholesale rates (FERC) and away from the regulation of retail rates (this Commission). Whether generation is divested or not, FERC will decide the prices at which generators can bid into the central market. If the generators cannot demonstrate lack of market power, they would be required to bid in cost-based rates. FERC is thus indifferent to ownership, it will regulate according to its precedent and practices.

While divestiture is certainly not required, whether any generation divestiture is desirable would have to be the subject of careful study, taking into account the size of the market, the locational and ownership patterns of generation, the ease of new entry, and the relative costs and benefits of divestiture.

8. What are the costs of the transition to retail electric competition, how should those costs be quantified, and who should bear them?

Of course, ultimately customers will bear the costs. The start up costs will be significant:

1. *Stranded costs.*[14] These will be in the billions. All Arizona utilities have built significant generation since stranded cost recovery in the 1990s. These include coal and natural gas fired facilities and solar, wind and geothermal projects, and environmental upgrades at certain facilities. All customers will bear these costs through non-bypassable charges.

2. *Costs to establish a market.* According to a FERC Staff report on cost ranges for the development and operation of RTOs, prepared in 2004, RTOs required an investment outlay of between $38 million and $117 million. This level of investment provides for open access transmission service, scheduling authority and available transmission capacity (ATC) determination, re-dispatch for congestion management, ancillary services, planning, parallel path flow mitigation, interregional coordination and market monitoring. This level of investment does <u>not</u> include costs associated with bid-based, security-constrained economic dispatch, unit commitment, locational prices, financial transmission rights or capacity markets as the Northeast and California ISOs have.[15]

While the 2004 FERC study found that RTOs had an annual revenue requirement of between $35 million and $78 million, annual operation costs have significantly increased over time. Currently, the cost to operate MISO is $227 million,[16] ISO New England's 2013 operating budget is $165 million,[17] the California ISO's proposed 2013 budget is $196 million, an increase of $1.2 million from 2012,[18] the operating expenses of the New York ISO totaled $155 million in 2011,[19] and PJM's service fees for 2012 were $278.2 million, an

[14] Stranded costs are the difference between the depreciated capital costs of generation built to serve customers under a regulatory compact, and the market value of the generation in a competitive market.
[15] Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization, Docket No. PL04-16-000, Prepared by the Staff of the Federal Energy Regulatory Commission, October 2004. Available at http://www.ferc.gov/EventCalendar/Files/20041006145934-rto-cost-report.pdf
[16] MISO Value Proposition. Available at https://www.midwestiso.org/WhatWeDo/ValueProposition/Pages/ValueProposition.aspx
[17] ISO New England 2013 Regional Electricity Outlook, at 35. Available at http://www.iso-ne.com/aboutiso/fin/annl_reports/2000/2013_reo.pdf
[18] CAISO 2013 Budget and Grid Management Charge Rates, December 6, 2012 Draft, at 4. Available at http://www.caiso.com/Documents/2013FinalBudget-GMCRatesBook.pdf
[19] 2011 Annual Report, New York Independent System Operator, at 30. Available at http://www.nyiso.com/public/flipbooks/NYISOAnnual2011/index.html

increase of $20.8 million from 2011.[20] These costs would be borne by Arizona consumers and would be under the jurisdiction of FERC not the ACC.

FERC Staff noted in its report that many of the operating costs are for reliability-related functions, such as transmission service, scheduling authority and available transmission capacity (ATC) determination, re-dispatch for congestion management, ancillary services, planning, parallel path flow mitigation, and interregional coordination, functions which Arizona's utilities currently manage efficiently and cost-effectively.

3. *Costs to retool billing systems, train employees, and establish codes of conduct* (this was done once, and no longer exists). We do not have accurate figures on the costs of implementing these systems this time but, the last time SRP developed these systems (1998) it cost more than $35 million and this number does not include the staff time.

4. *Costs to educate customers.* In 1998, SRP spent well over $1 million. Today, statewide, the costs will be considerably higher.

5. *Regulatory costs.* Costs to develop and adjudicate all the market rules and structural components will be significant, in the millions if not hundreds of millions of dollars.

Of course, these are rough estimates and examples. Precise costs are dependent on the market structure, rules, and timing ultimately selected. It is difficult to forecast all the costs that might be incurred lacking specificity at this point.

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[20] PJM 2012 Financial Report, Dynamic Performances, at 9. Available at http://www.pjm.com/~/media/about-pjm/newsroom/annual-reports/2012-financial-report.ashx

9. Will restructuring impact reliability? Why or why not?

Responding to this question SRP addresses reliability, as well as other attributes of electric service that are important to customers.

Reliability

As stated in SRP's cover letter, reliability is the key issue. Without a stable customer base, utilities cannot finance new projects. There is no economic incentive for long term planning. Reliability will be the major victim of restructuring.

As excess capacity is used up, reliability and in particular lack of sufficient generating capacity is an ever increasing concern in restructured states. In January 2013, the CEO of the North American Electric Reliability Corporation (NERC), Gerry Cauley, sent a letter to the CEO of the Electric Reliability Council of Texas (ERCOT) expressing concern over reliability in Texas stating that "[c]apacity resources in ERCOT have drifted to a level below the Planning Reserve Margin target and are projected to further diminish through the ten-year period covered in the assessment." Cauley also reminded ERCOT that this was not the first time NERC has raised these concerns with ERCOT.[21]

In response, while ERCOT understood NERC's concerns and noted that resource adequacy is an important issue, ERCOT had to admit that its long-term Capacity, Demand and Reserves report indicated that planning reserve margins could drop well below its 13.75 percent target within the coming years with a December 2012 report indicating that the planning reserve margin could fall to 13.2 percent as soon as summer 2013 and will continue to tighten over time without investment in new generation resources and demand response in the region.[22]

More recently, in May 2013, ERCOT stated that, "[w]ith tight operating reserves expected this summer, especially during the late afternoon hours on the hottest days, it is likely that ERCOT will initiate conservation alerts or power watches on some days. These alerts ask the public to reduce electric use to help ERCOT maintain reliability of the grid." ERCOT also noted that increased power demands could lead to implementation of Energy Emergency Alert actions with the possibility of rotating outages if needed to protect the grid.[23]

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[21] NERC, Letter from Gerry Cauley to Trip Doggett, January 7, 2013. Available at http://www.ercot.com/content/news/presentations/2013/NERClettertoTripDoggettonResourceAdequacyJan72013.pdf

[22] Statement of ERCOT CEO Trip Doggett regarding January 7, 2013, letter from NERC CEO Gerry W. Cauley. January 16, 2013. Available at http://www.ercot.com/news/press_releases/show/26390

[23] ERCOT expects tight summer conditions, long-term outlook shows improvement. May 1, 2013. Available at http://www.ercot.com/news/press_releases/show/26433

In addition to possible outages, reliability issues can affect cost. "In recent years, fast-growing demand on the system has strained the transmission grid in West Texas, especially around Odessa. When the wires used to deliver electricity become congested, like a busy roadway during rush hour, ERCOT can have generators send power where it is needed through less congested circuits, and that power sometimes comes from more costly generation sources. While this process is sometimes necessary to keep up with power demand and protect the grid, it can affect the cost of power in that 'load zone.'"[24]

In an attempt to minimize the risk associated with dwindling reserve margins, the Public Utility Commission of Texas voted at the end of October 2012 to step up price caps in the state's wholesale power market. The cap would increase first to $5,000/MWh effective June 1, 2013, then to $7,000/MWh effective June 1, 2014, and finally to $9,000/MWh effective June 1, 2015 to help generators realize more revenue.[25] However, according to an analysis conducted by ICF International, ERCOT's system-wide offer cap would have to rise above $15,000/MWh for the market to sustain a 13.75 percent target reserve margin and generate adequate price signals for new entrants. But even if price caps were to increase that much, the weather-driven risk means the market may not bear the net cost of new entry required for new entrants.[26]

Although a top newsmaker, Texas is not the only deregulated state facing reliability issues. Two of the nation's largest regional transmission organizations (RTOs), PJM and MISO, currently have a docket open with FERC as they struggle to resolve capacity deliverability issues at their seam, which ultimately affects reliability and costs for customers in PJM and MISO.[27] Five years ago, PJM established a capacity market to try to deal with the issue within its borders. The market only seeks capacity assurance three years into the future. Much of the capacity offered over the past five years has been demand-side management, and no central station plants have been proposed or built in PJM during this period. While reserve margins are currently adequate there, the heavy reliance on demand side reductions and the lack of any projects adding base load capacity are troubling to many observers of that market.

California is also struggling with how to ensure adequate capacity in the future, especially the kind of capacity that is needed to integrate intermittent renewable resources into the system. One of the characteristics of this capacity is that they may not run that often, but

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[24] ERCOT Board of Directors receives updates on summer preparedness, West Texas congestion. May 21, 2013. Available at http://www.ercot.com/news/press_releases/show/26448

[25] Texas electric prices cap to double over 3 years, Chris Tomlinson, Bloomberg BusinessWeek, October 26, 2012, Available at http://www.businessweek.com/ap/2012-10-26/texas-electric-prices-cap-to-double-over-3-years.

[26] ICF International, ERCOT Scarcity Pricing: Potential and Risks, February 26, 2013. http://www.icfi.com/insights/webinars/2013/recording-ercot-scarcity-pricing-potential-and-risks

[27] FERC Docket No. AD12-16-000; Presentations on this issue were presented to FERC at its June 20, 2013 Open Meeting and are available at http://www.ferc.gov/

are absolutely essential to reliability. California has not yet fully determined how it plans to solve its capacity problems.

SRP, along with many other Arizona utilities, is a member of the Southwest Reserve Sharing Group (SRSG) which allows Arizona utilities to protect its customers in emergency and outage situations. SRSG Participants share contingency reserves to maximize generator dispatch efficiency. Shared reserves decrease costs of compliance with the Disturbance Control Standard and contribute to electric reliability in the Western Interconnection.[28]

But more importantly the Arizona utilities are serious in planning reserves and diversity to meet their service obligations. The regulatory compact and the planning that results from it, have served Arizona well.

Fuel Diversity

As discussed above, prices for all customer classes in almost every deregulated state are higher than corresponding prices in Arizona, despite recent low natural gas prices. The data presented above, however, only partially shows a more recent reduction in prices for deregulated states which is almost entirely due to lower natural gas prices. The increasing reliance on natural gas in restructured states does have this short-term benefit. But it also creates longer-term risks in two ways. First, the over-reliance of any utility system on a single fuel raises reliability issues if that fuel becomes in short supply. In the case of natural gas, a system over-reliant on gas becomes vulnerable to external factors such as increasing exports, pipeline capacity shortages, storage problems and limitations, freezing weather, and pipeline outages or even artificial shortages. If there are problems with natural gas delivery or prices become too high, these utilities have nowhere else to turn. Fuel diversity is an important component of ensuring a robust and reliable electric system.

Arizona is able to provide low, stable prices to its customers, mostly due to its diversified energy resource mix and efficient system operations. Arizona electric customers benefit from currently low coal and natural gas prices but, because of a diversified resource mix, are sheltered from price spikes or shortages of any one resource fuel. Additionally, for SRP, for example, 18 percent of its resource mix is purchased power, most of which is pursuant to long- and short-term contracts, mitigating wholesale spot price volatility for our customers and again providing increased supply diversity.

Lack of Regulatory Certainty

On June 20, 2013, citing regulatory uncertainty introduced by the Arizona Corporation Commission's review of retail competition, Jefferies LLC downgraded UNS Energy Corp.

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[28] For more information see http://www.srsg.org/

shares to "hold" from "buy" and decreased its price target to $49.50 from $57.[29] This lack of regulatory certainty has also led Arizona Public Service to further delay its purchase of Southern California Edison's interest in the Four Corners Generating Station, potentially causing issues for APS with the U.S. Environmental Protection Agency.

In its filing, APS stated that in light of the ACC's recent inquiry into deregulation, "APS currently expects that it will not be in a position to close the Four Corners purchase transaction with SCE until the ACC's intentions with regard to pursuing deregulation in Arizona become clearer."[30] While APS has said that it is working to keep options open for regulatory approvals required to complete the transaction, the U.S. EPA, in its final regional haze rule for Four Corners, set a date of July 1 for the Four Corners owners to elect one of two emissions alternatives, both of which would involve substantial investment in pollution controls.

In light of the ACC deregulation proceeding, APS said it is in discussions with the EPA concerning the utility's request to extend the July 1 deadline.[31] While APS may be the operator of the Four Corners Generating Station, this decision has implications for the other co-owners of the plant, including SRP and TEP, not to mention other entities beyond the jurisdiction of the ACC, including Public Service Company of New Mexico, Southern California Edison, and El Paso Electric.

While SRP operates somewhat independently from the ACC, the regulatory uncertainty or a move toward deregulation will eventually impact SRP and resource investment decisions it has to make.

<u>Long-term Resource Planning</u>

See response to question 17.

[29] Jefferies Downgrades Unisource Energy on Regulatory Concerns (UNS), Dividend Daily, June 20, 2013, Available at http://markets.cbsnews.com/cbsnews/news/read/24476416/jefferies_downgrades_unisource_energy_on_regulatory_concerns

[30] APS further delays purchase of Four Corners units, Patrick O'Grady, June 18, 2013. Available at http://www.bizjournals.com/phoenix/news/2013/06/18/aps-further-delays-purchase-of-four.html

[31] Four Corners Power Plant purchase on hold, The Daily Times - McClatchy-Tribune Information Services, June 24, 2013, Available at http://www.otcmarkets.com/news/otc-market-headline?id=15224360

10. What are the issues relating to balancing area authorities, transmission planning, and control areas which must be addressed as part of a transition to retail electric competition?

It is easy to say that we do not have to change anything; that current FERC rules are adequate. But, as we look at other markets, we see that few of them retain the vestiges of vertically integrated utilities. If there is a truly disaggregated market, then there is little point in retaining the various control areas and transmission planning driven by the needs of particular utilities. Probably, as the deregulated markets mature Arizona will be dragged into the RTO structure existing in many parts of the country. An RTO would likely provide a single control area and balancing authority for the region in which it operates. Transmission planning would become solely reactive to where generation (driven by the market) decides to locate.

11. Among the states that have transitioned to retail electric competition, which model best promotes the public interest for Arizonans? Which model should be avoided?

SRP has engaged in its own independent review of each state that has deregulated or partially deregulated. **This analysis is attached as Appendix A**. This analysis is enlightening as it shows that no jurisdiction has a "model" that works. Each jurisdiction continues to make changes and add features to replace the elements of planning, reliability, stable pricing and service levels that were lost when deregulation took effect.

The conclusion drawn from SRP's review is that the current regulated model best serves the public interest in Arizona.

All the jurisdictions, and even states with limited restructuring, seem to mix traditional regulation and market principles in attempts to correct for market deficiencies related to generation capacity and supply, deliverability, congestion, high prices, and lack of participation by certain customer classes, as discussed throughout these comments. Attempts to fix these issues by legislatures and/or PUCs further complicate the situation, making the provision of reliable electric supply more expensive for customers and burdensome for utilities, electric service providers, market operators, and Commission Staff. Across the board, some worse than others, these states are struggling with the fact that the market does not address long term capacity additions

12. How have retail rates been affected in states that have implemented retail electric competition?

SRP's response to question one responds to this question.

13. Is restructuring viable in Arizona in light of the Court of Appeals decision in Phelps Dodge Corp. v. Ariz. Elec. Power Coop., 207 Ariz. 95, 83 P.3d 573 (App. 2004)? Are there other legal impediments to the transition to and/or the implementation of retail electric competition?

The short answer is no. Our constitution mandates a system of *regulation*. That is definitionally and categorically inapposite to *deregulation*. "Should they think it wise, our citizens are free to amend the Arizona Constitution". *US West Communications v. Arizona Corp. Com'n.*, 201 Ariz. 242, 246, 34 P.3d 351, 355 (2001).

Here SRP sets out a high level analysis of the two key legal issues presented by the proposal. SRP will expand on this discussion if requested to do so by the Commission. In summary, the concept of *deregulation* as expressed in the Commission rules fails under the Arizona Constitution. Additionally, because of past failures and due to its unconstitutional premise, the Electric Power Competition Act fails as well.

1. *<u>Deregulation violates the Arizona Constitution</u>*

Our Constitution mandates *regulation* to assure that rates are "just and reasonable". *Deregulation* would leave that determination to the marketplace. The two are inconsistent. Now, certainly there is room to argue either way. And, if the Commission moves forward most certainly the parties will spend years doing so. But, it is hard to envision a winning case for "deregulation".

Until 2001, Arizona law was clear. The Commission was required to find "fair value" and use that finding in a formulaic way to set "just and reasonable" rates. This concept was supported by a long line of cases. *See e.g., State v. Tucson Gas, Elec. Light & Power Co.*, 15 Ariz. 294, 303, 138 P. 781, 785 (1914); *Ethington v. Wright*, 66 Ariz. 382, 189 P.2d 209 (1948); *Simms v. Round Valley Light & Power Co.*, 80 Ariz. 145, 294 P.2d 378 (1956); *Ariz. Corp. Comm'n. v. Ariz. Water Co.*, 85 Ariz. 198, 202, 335 P.2d 412, 414 (1959).

But in 2001 the Supreme Court issued a decision in the face of the 1996 federal mandate of competition in the communications industry. In *US West Communications v. Arizona Corp. Com'n.*, 201 Ariz. 242, 34 P.3d 351, (2001) (*US West II*) the Court held that the formulaic determinations in monopolistic markets did not necessarily apply in competitive markets. Yes, the Commission is still required by the Constitution to find "fair value" and use that determination to set "just and reasonable" rates. But, in a competitive market, "[t]he commission has broad discretion . . . to determine the weight to be given [fair value] in any particular case."[32] The Court did not exactly say how this would work.

[32] *US West Communications v. Arizona Corp. Com'n.*, 201 Ariz. 242, 246, 34 P.3d 351, 355 ¶ 21 (2001)

It is an interesting question as to whether the Court would have held as it did if it were not faced with the federal mandate that threatened to preempt the Arizona Constitution. Or, absent the federal act, whether the Commission even has authority to establish competitive markets. But putting these questions aside we turn to the *Phelps Dodge* case[33], which applied the principles of the Constitution to deregulated electric markets.

The Court in *Phelps Dodge* found that the Commission rules approving market based rates were unconstitutional. Following the *US West II* case, the Phelps Dodge Court left the door open; there may be approaches that are not unconstitutional. But, Phelps Dodge set a standard that is simply not workable in a "deregulated" market. Here is what the Court held:

- The Commission must ensure that rates are "just and reasonable" for both the consumers and the public service corporations. [*Id.* 207 Ariz. at 106, 83 P.3d at 584]
- The Commission must provide consumer protection against overreaching by public service corporations. [*Id.* 207 Ariz. at 106, 83 P.3d at 584]
- The Commission may not abdicate its constitutional responsibility to set just and reasonable rates by allowing competitive market forces alone to do so. [*Id.* 207 Ariz. at 107, 83 P.3d at 585]
- The Constitution charges the Commission, not the customers, with the duty to discover and remedy overreaching. [*Id.* 207 Ariz. at 107-108, 83 P.3d at 585-586]
- It is the duty of the Commission to avoid the potential for abuse in pricing by insuring that customers are charged just and reasonable rates. [*Id.* 207 Ariz. at 107, 83 P.3d at 585]
- The Commission must determine whether market rates are excessive. [*Id.* 207 Ariz. at 108, 83 P.3d at 586]
- The Commission must ensure that the prices are fair also to the ESPs, and cannot just let prices be set by the market. [*Id.* 207 Ariz. at 108, 83 P.3d at 586]
- The Commission must find "fair value" and use that finding in a meaningful way to assure just and reasonable prices. [*Id.* 207 Ariz. at 105, 106, 108, 83 P.3d at 583, 584, 586]

These requirements are simply inconsistent with the concept that market will set retail prices.

[33] *Phelps Dodge v. Arizona Electric Power Co-op, Inc.*, 207 Ariz. 95, 83 P.3d 573 (App. 2004)

In addition, any attempt at reviving deregulation must address the fact that the Commission can only offer an incomplete solution to restructuring the industry. Specifically the *Phelps Dodge* case finds that the Commission is without authority to order divestiture [*Id.* 207 Ariz. at 113, 83 P.3d at 591] or to order the participation in a central market structure. [*Id.* 207 Ariz. at 112, 83 P.3d at 590]

So we are left with this question: does the system of "deregulation" fit within our Constitutional system of "regulation"? Under current law the answer is no.

2. <u>The Electric Power Competition Act is no Longer Applicable</u>

In 1998 the Legislature enacted the Electric Power Competition Act mandating that public power entities, such as SRP, open their distribution systems to competitive providers certificated by the Commission. The law was intended to be a companion to the Commission's competition rules. But, that law was premised on the proposition that "market based rates are just and reasonable" and was also premised on the proposition that "competition" under the Commission's rules would begin between 1998 and 2000.

Both these premises have failed. Specifically:

1. The Act provides:

> In supervising and regulating public service corporations, it is the public policy of this state that the most effective manner of establishing just and reasonable rates for electricity is to permit electric generation service prices to be established in a competitive market.

But, the Phelps Dodge case held:

> [T]he Commission cannot carry out its constitutional mandate by allowing competitive market forces to exclusively determine what is "just and reasonable."

2. The Act directs the Corporation Commission to open the service territories for competition:

> After December 31, 2000 service territories established by a certificate of convenience and necessity shall be open to electric generation service competition for all retail electric customers for any electricity supplier that obtains a certificate from the commission pursuant to section 40-207 or any public power entity.

The service territories have not been "open" for competition in over thirteen years.

3. Many of the provisions of the Act are premised upon a start of competition in the 1998 to 2000 time frame, including the directives regarding stranded costs, the directives regarding price reductions and the directives for consumer education. The fundamental premise of these provisions has failed through the passage of time.

The Act itself in section 36 directs that provisions of the Act are not severable where an invalidity of a part of the Act affects the whole. This is the case here. It will be up to the legislature, to the extent that this can be done consistent with SRP's contracts with the United States and the Constitution, to act if the Commission were to move to a new model of deregulation.

14. Is retail electric competition compatible with the Commission's Renewable Energy Standard that requires Arizona's utilities to serve at least 15% of their retail loads with renewable energy by 2025? (See A.C.C. R14-2-1801 *et seq.*).

15. Is retail electric competition compatible with the Commission's Energy Efficiency Standard that requires Arizona electric utilities to achieve a 22% reduction in retail energy sales by consumption by 2020? (See A.C.C. R14-2-2401 et seq.).

16. How should the ACC address net metering rates in a competitive market?

SRP will answer these three questions together, as they are interrelated.

It *is* possible to integrate renewable and energy efficiency standards into a deregulated market. It could be, and it has been done in other states. The obligation could reside with the distribution companies, or it could be spread out among the competitive generators.

But to properly relate competition with a mandatory renewables and energy efficiency standard will require a very careful determination of costs and an unbundling of prices. We would likely see significant price swings (not just with solar customers) as prices moved suddenly to unbundled costs.

Additionally, if the RES responsibility is spread among generators, and hence the function is being performed by each power marketer, Arizona will likely lose the efficiency and innovation brought about by focusing this function with the dedicated Arizona utilities.

On the issue of energy efficiency, it may be difficult for a customer to determine energy efficiency savings with market prices constantly in fluctuation. As stated by Edan Rotenberg of the Yale Law School, in his article *Energy Efficiency in Regulated and Deregulated Markets*[34]:

> Price regulation, by definition, largely disappears in a competitive market. There is no longer a regulator who sets a

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[34] Edan Rotenberg, *Energy Efficiency in Regulated and Deregulated Markets*, 24 U.C.L.A. J. Envitl. L & Pol'y 259 (2006). Page 30, available at http://digitalcommons.law.yale.edu/cgi/viewcontent.cgi?article=1013&context=student_papers&sei-redir=1&referer=http%3A%2F%2Fwww.google.com%2Furl%3Fsa%3Dt%26rct%3Dj%26q%3Denergy%2520efficiency%2520in%2520regulated%2520and%2520deregulated%2520markets%2520edan%2520rotenberg%26source%3Dweb%26cd%3D1%26cad%3Drja%26ved%3D0CC8QFjAA%26url%3Dhttp%253A%252F%252Fdigitalcommons.law.yale.edu%252Fcgi%252Fviewcontent.cgi%253Farticle%253D1013%2526context%253Dstudent_papers%26ei%3D12LgUf-hPOSRiQLl_oHwDA%26usg%3DAFQjCNEwNz6nnYVQCBZMEswo9_P2IjQTBA%26bvm%3Dbv.49260673%2Cd.cGE

> price and can demand that utilities work with customers to achieve all energy savings below that price. Every retail provider sets their own price and earns money solely on the basis of sales, not through some regulated subsidy that compensates them for earnings lost to efficiency investments. Instead, if efficiency gains are to be made they must be made directly by end users, or by third parties that provide energy management services to end users. This means that price is even more important to the achievement of energy efficiency in a deregulated market than it is in a regulated market. To the extent that prices do not reflect social cost, or to the extent that information and transaction costs impede the functioning of markets, energy efficiency will be even harder to achieve in a competitive market than it was in a monopolized market. In a competitive retail market a regulator can encourage private sector conservation measures, but the achievement of performance contracting will depend critically on the cost of electricity.

Regarding net metering, it is theoretically possible to keep net metering in a deregulated market. But, as the unbundled market prices will not support net metering, Arizona would need to develop an alternative funding mechanism.

17. What impact will retail electric competition have on resource planning?

Under a restructured market, resource planning is mostly eliminated as the generators shift from a centralized planning approach to one that is market-driven. Such a market-driven approach erodes long term resource planning efforts and reliability as decisions on what and when resources should be built is largely determined by unregulated power plant developers whose main objective is to maximize their revenue stream and profits and minimize their financial risk. As a result, there tends to be more emphasis on short-term, least cost or less capital-intensive resources that lead to less fuel diversity than under the current paradigm. Investments in renewable resources, energy efficiency and other public policy considerations may be ignored or greatly impacted under such market-driven approach.

Throughout the restructured markets of Texas and the eastern states, shrinking reserves and tight power supply situations are common as a result of a reluctance to develop generation. In the restructured markets of Texas, the Public Utility Commission is conducting an inquiry into a recent study completed by ERCOT that analyzed energy-weighted average price increases in 2011 and 2012 under a real-time scarcity pricing proposal that is aimed at encouraging generation development. A recent news publication reported "As the PUCT works on scarcity pricing, ERCOT is expecting Texas to see a tight power supply situation this summer, with reserves shrinking further in the coming years as generation development fails to keep pace with power demand growing from economic development."

Meanwhile ERCOT on June 1 raised the high system-wide offer cap to $5,000/MWh for energy and ancillary services. ERCOT July products have been trading in the high $60s across the board, with ERCOT West in the lead and ERCOT South pulling up the rear at just $2 below West."[35]. NERC recently released its report on this summer's 2013 summer reliability assessment, noting that ERCOT's planning reserve margin for this summer is below NERC's minimum target reserve margin level for ERCOT of 13.75 percent which could lead to increased risk of emergency operating conditions, including curtailments and rotating outages.[36]

Because there is generally no mechanism in place to encourage new generation to be built in restructured states, states such as New Jersey and Maryland have utilized legislative and

[35] "Texas regulators get earful of opinions about scarcity power pricing proposal," Christine Cordner, SNL Financial (June 4, 2013). Available at http://azpowerconsumers.com/article/texas-regulators-get-earful-of-opinions-about-scarcity-power-pricing-proposal

[36] "2013 Summer Reliability Assessment," NERC, Page 38 (May 2013). Available at http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013SRA_Final.pdf.

formal Requests for Proposals in an attempt to support the development of new resources to ensure resource adequacy in their states.[37]

In addition, two of the nation's largest regional transmission organizations (RTOs), PJM and MISO, currently have a docket open with FERC as they struggle to resolve poor scheduling interface along the PJM/MISO boundary. The central concern of such boundary issues is capacity deliverability and ultimately its effects on reliability and costs.[38]

[37] Synapse Energy Economics, Inc. *Incenting the Old, Preventing the New: Flaws in Capacity Market Design, and Recommendations for Improvement*, Page 3 (June 14, 2011). Available at http://www.synapse-energy.com/Downloads/SynapseReport.2011-06.APPA.Incenting-the-Old-Preventing-the-New.11-033.pdf
[38] FERC Docket No. AD12-16-000

18. How will restructuring affect public power utilities, cooperatives and federally controlled transmission systems?

This discussion is not intended to address the advantages or disadvantages of public versus investor owned utilities. But, it is important to note that most states that have chosen restructuring have given the elected officials of public power and cooperatives the option to opt in or out.

Texas is a good example, where three large public power entities have chosen not to participate in the "deregulated" markets: CPS Energy (San Antonio), Austin Energy and Lower Colorado River Authority (Central Texas). Additionally Texas has exempted the customer owned electric cooperatives.

Similarly in California the Los Angeles Department of Water and Power and the Sacramento Municipal Utilities District, as well as several smaller public power entities have chosen not to participate.

Studies have shown that the general level of prices in these non-participating jurisdictions has risen significantly less than their "deregulated" neighbors. Here is what the Texas Coalition for Affordable Power said in its December 2012 report: [39]:

> [I]t is clear that the millions of ratepayers still paying the Price To Beat in 2006 were getting an awful deal by paying unnecessarily high prices. And indeed, a separate review of rate filings showed that by 2006, the Price To Beat had increased by 84 percent in the Metroplex, by 81 percent in Houston, by 101 percent in Corpus Christi and by a whopping 116 percent in West Texas. Outside deregulated areas, price increases occurred over the same period but were much more modest. In Austin, with its municipally owned utility, rates increased by 19.4 percent, for example. That means the most commonly paid rate in deregulated Houston increased five times faster than the rate paid in Austin, which remained outside deregulation.

In Arizona, Salt River Project is the largest publicly owned electric utility. Also there are a large number of smaller municipal systems and systems operated by special taxing districts. Additionally Arizona is home to a number of customer owned cooperatives. The

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[39] Texas Coalition for Affordable Power *Deregulated Electricity in Texas, A History of Retail Competition* Page 40 (December 2012). Available at http://tcaptx.com/wp-content/uploads/2013/03/SB7-Report-2012.pdf

beneficiaries of these public power entities, through their elected officials, ought to have the right to make the decision on whether their utility is restructured, or not.

Salt River Project is a particular example of why this is so. SRP is a federal reclamation project. It is operated on behalf of the landowners in its district, under contract with the United States. It primary purpose is to store and deliver water to landowners in the Salt River Valley. Today most of SRP's customers are cities, which use the water stored and delivered by SRP to serve most of the homes and businesses in the Valley. There is nothing to be gained by putting SRP at risk. It should be the elected officials, representing the water users and the electric customers, who should make this choice.

Appendix A
Deregulated State Summaries

SRP has prepared a summary of activity in all fully deregulated states and a few selected states that have "limited" deregulation to provide some background on experience with deregulation efforts in other states. A majority of the information summarized below was derived from the 2012 Assessment of Choice in Canada and the United States (ABACCUS), which is an annually published scorecard that tracks U.S. states' and Canadian provinces' progress in restructuring electricity markets.[1] For additional information, SRP turned to SNL Energy, a subscription service to which SRP subscribes and which we have found to provide current, accurate, and factual information.[2] SNL Energy integrates news, data and research in real time for the electric power industry and allows users to access news, pricing, financial data and energy company research. Lastly, SRP relied upon documents from state and federal regulatory agencies, state legislatures, Regional Transmission Organizations and Independent System Operators, as well as local news sources, in order to provide recent updates on state deregulation activities that were not captured in the previously mentioned resources.

ABACCUS ranks the states according to whether deregulation efforts are "excellent," "good," "marginal," or "unsatisfactory." Rather than organize the states alphabetically, the summaries below are first organized by fully deregulated states followed by states with limited deregulation, and then according to ABACCUS rankings, from excellent to unsatisfactory, to more clearly categorize the states' experiences with deregulation efforts.

Table of Contents

[1] Distributed Energy Financial Group, LLC, 2012 ABACCUS: An Assessment of Restructured Electricity Markets (December 2012). Available at http://defgllc.com/publication/2012-abaccus-electricity-restructuring-scorecard/

[2] Information about SNL Energy may be found at http://www.snl.com/Sectors/Energy/Default.aspx

Texas

History

- In 1999, the Texas legislature adopted the Texas Electric Choice Plan.[3] Pursuant to that legislation, integrated electric utilities operating within the Electric Reliability Council of Texas (ERCOT), were required to unbundle their integrated operations into separate affiliated retail electric providers (AREPs), power generation companies (PGC), and transmission and distribution companies (TDUs) by January 1, 2002.[4]
- The legislation provided for a transition period to move to the new market structure and provided a true-up mechanism for the formerly integrated electric utilities to recover stranded and certain other costs resulting from the transition to competition. These costs were recoverable after approval by the Public Utility Commission of Texas (PUCT) either through the implementation of a competition transition charge (CTC) as a rider to the utility's tariff or the issuance of securitization bonds.[5]

2012 Annual Average Retail Price[6]

- Residential: 11.05 cents per kWh
- Commercial: 8.18 cents per kWh
- Industrial: 5.72 cents per kWh

Reliability/Capacity Issues

- Texas capacity is projected to be below the Planning Reserve Margin Target by summer of 2013, raising reliability concerns at the North American Electric Reliability Corporation (NERC), ERCOT, and the PUCT.[7]

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[3] Texas Legislature, SB 7, Effective September 1, 1999. Available at http://www.legis.state.tx.us/billlookup/History.aspx?LegSess=76R&Bill=SB7
[4] Texas Utilities Code, Title 2, Subtitle B, Chapter 39, Subchapter B, Sec. 39.051. Available at http://www.statutes.legis.state.tx.us/Docs/UT/htm/UT.39.htm
[5] Texas Utilities Code, Title 2, Subtitle B, Chapter 39, Subchapters E and F. Available at http://www.statutes.legis.state.tx.us/Docs/UT/htm/UT.39.htm
[6] All 2012 annual average retail price information is from the U.S. Energy Information Administration Electricity Data Browser, Average Retail Price of Electricity Data Set. Available at http://www.eia.gov/electricity/data/browser/ Data utilized in the browser is compiled from the following EIA survey sources (including predecessor forms): Form EIA-826, "Monthly Electric Utility Sales and Revenues with State Distributions Report," Form EIA-923, "Power Plant Operations Report," EIA-860, "Annual Electric Generator Report," and the EIA-861, "Annual Electric Power Industry Report."
[7] *See* NERC letter to ERCOT CEO Trip Doggett, January 7, 2013, available at http://www.ercot.com/news/press_releases/show/26390; Statement of ERCOT CEO Trip Doggett regarding Jan. 7, 2013 letter from NERC CEO Gerry W. Cauley, January 16, 2013, available at

- In an attempt to minimize the risk associated with dwindling reserve margins, the PUCT voted at the end of October 2012 to step up price caps in the state's wholesale power market. The cap would increase first to $5,000/MWh effective June 1, 2013, then to $7,000/MWh effective June 1, 2014, and finally to $9,000/MWh effective June 1, 2015 to help generators realize more revenue.[8]

Treatment of Residential Customers

- Once deregulation began, residential and small commercial customers who did not affirmatively select a provider were served by the AREP under capped "price-to-beat" (PTB) rates through 2006. Provider-of-last-resort (POLR) service is available only to customers who are disconnected from their selected REP. Such service is intended to be temporary, and POLR suppliers are designated for each utility service territory by the PUCT, subject to rules that are revised periodically. Generally, POLR suppliers are permitted to charge prices that include a premium over prevailing market rates.
- As of June 2012, 58.76% of residential customers switched providers.[9]

Mandated Rate Reductions

- Utilities were required to freeze their rates beginning on September 1, 1999. When the deregulated market opened on January 1, 2002, retail electric providers affiliated with the utilities were required to charge a price that was 6% less than the regulated rate that existed on December 31, 2001. This was the PTB and it was available until January 1, 2007. Providers were able to increase or decrease the rate no more than twice each year to reflect changes in natural gas fuel prices.
- Until 2005, the PTB was the only rate that the provider affiliated with the former electric company was allowed to charge residential and small commercial customers in the old service area. The PTB created a target for competitors to undercut with lower prices. A provider affiliated with a former electric company was required to offer the PTB rate until 2007. However, it also could offer plans with alternative prices after 2005, if it could demonstrate that it had lost more than 40 percent of its customers.

Current Actions at PUC/ISO/RTO/Legislature

- In addition to the capacity and reliability issues discussed above, the Texas legislature took action in 2013 to address the growing, yet unused, System Benefit Fund. The fund was created in 1999 to help electricity customers, especially those of modest means. By law, it is supposed to pay for bill discounts, home weatherization assistance, and customer education. All Texas electricity customers pay for it

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http://www.ercot.com/news/press_releases/show/26390; and Report on the Capacity, Demand, and Reserves
in the ERCOT Region, December 2012, available at http://www.ercot.com/news/presentations/

[8] Chris Tomlinson, *Texas electric prices cap to double over 3 years*, Bloomberg Businessweek (October 26, 2012).

[9] Distributed Energy Financial Group, LLC, 2012 ABACCUS: An Assessment of Restructured Electricity Markets at 92 (December 2012). Available at http://defgllc.com/publication/2012-abaccus-electricity-restructuring-scorecard/

through a fee on their electric bills. Beginning in 2003 the legislature began diverting the money to "balance" the budget. Thousands of low-income Texans ended up paying more for electricity than they otherwise would have. HB7 directs the PUCT to set the System Benefit Fund fee at zero cents per MWh for the period beginning September 1, 2013 and ending September 1, 2016, with the $800 million fund balance used to reduce rates for low income customers over the summer months in 2014 through 2016.[10]

Divestiture

- In 2000, Central and South West and American Electric Power merged. The PUCT approved a merger-related settlement under which AEP Texas Central, Southwestern Electric Power, and AEP Texas North implemented base rate reductions totaling $52.7 million, $16.1 million, and $15.6 million, respectively. AEP Texas Central was required to divest 1,604 MW of generation capacity; the divestiture occurred as part of the electric-industry-restructuring-process, and the proceeds were used to offset stranded costs.[11]
- In 2002, American Electric Power divested its retail businesses in AEP Texas Central and AEP Texas North's service territories to Centrica, plc. subsidiaries CPL Retail Energy (CRE) and WTU Retail Energy (WRE).[12]

Illinois

History

- In December 1997 and September 1999, the Illinois Public Utilities Act was amended allowing large customers to choose their supplier in 1999, and other nonresidential customers to choose in 2000.[13]
- In 2007, the Illinois Power Agency Act[14] declared services to be competitive for Commonwealth Edison (ComEd) and Ameren Illinois (Ameren) customers with peak demand > 400 kW as of August 2007 and set deadlines for when certain customers must stop taking bundled service:
    - For ComEd:
        - customers with peak demand >400 kW could take bundled service until June 2008; customers with peak demand between 100 kW and 400 kW could take bundled service until June 2010.

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[10] Texas 83rd Legislative Session, HB 7. Available at http://www.legis.state.tx.us/BillLookup/History.aspx?LegSess=83R&Bill=HB7

[11] SNL Energy, Regulatory Research Associates, Commission Profiles, Texas, Merger Activity. (Updated March 25, 2013)

[12] SNL Energy, Regulatory Research Associates, Commission Profiles, Texas, Merger Activity. (Updated March 25, 2013)

[13] Electric Service Customer Choice and Rate Relief Law of 1997, Public Act 90-0561, Illinois HB 362. Available at http://www.ilga.gov/legislation/publicacts/pubact90/acts/90-0561.html

[14] Illinois Power Agency Act, Public Act 95-0481, Illinois SB1592, effective August 28, 2007. Available at http://www.ilga.gov/legislation/publicacts/fulltext.asp?Name=095-0481

- For Ameren:
    - customers with peak demand >1 MW could take bundled service until June 1, 2008; customers with peak demand between 400 kW and 1 MW could take bundled service until June 1, 2010.

2012 Annual Average Retail Price

- Residential: 11.42 cents per kWh
- Commercial: 8.19 cents per kWh
- Industrial: 5.91 cents per kWh

Reliability/Capacity Issues

- Public Act 96-0176 amended the Illinois Power Agency Act effective January 1, 2010 to allow municipalities and counties to aggregate electrical load.[15] Municipal corporate authorities and county boards can adopt an ordinance to aggregate residential and small commercial electrical loads and solicit bids for the sale and purchase of electricity. A referendum is required to determine whether or not the aggregation shall be an opt-out program.
- In February 2013, a new director was chosen for the Illinois Power Agency. The outgoing director noted that the next director's challenge would be to manage increasing risk. The power demand met by the utilities has shrunk dramatically as most municipalities, including the city of Chicago, have moved to buy electricity on behalf of their households. If prices go up in the future, municipalities may decide to no longer act on their residents' behalf, sending those customers back to the utility, leading to uncertainty in the default service obligation.[16]

Treatment of Residential Customers

- The 2007 Illinois Power Agency Act codified the provisions of an electric rate compromise reached among state legislators, the Attorney General, the state's utilities, and power generation companies, requiring the utilities and power generation companies to contribute over $1 billion ($800 million from Exelon, $150 million from Ameren, and $50 million from competitive suppliers) to fund various customer "rate relief" programs designed to mitigate the impact of market-based pricing on residential customers. These programs were in place from 2007 through December 31, 2010.[17]

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[15] Illinois Power Agency Act amendments, Public Act 096-0176. Available at http://www.ilga.gov/legislation/publicacts/fulltext.asp?Name=096-0176

[16] Steve Daniels, *New chief tapped for Illinois Power Agency*, Crain's Chicago Business. (February 19, 2013). http://www.chicagobusiness.com/article/20130219/NEWS11/130219751/new-chief-tapped-for-illinois-power-agency#ixzz2XpSU4Xa4

[17] Illinois Power Agency Act, Public Act 95-0481, Illinois SB1592, effective August 28, 2007, at 220 ILCS 5/16-111.5A. Available at http://www.ilga.gov/legislation/publicacts/fulltext.asp?Name=095-0481

- The Power Agency Act also dictates that the Illinois Commerce Commission (ICC) cannot make a determination of competition for residential customers, with peak demand less than 100 kW, until after July 1, 2012.[18] Such a determination has yet to be made.
- As of March 31, 2013, between 42.5% and 74.4% of residential customers in ComEd and Ameren service territories were taking supply service from a retail electric supplier.[19]
- Both Ameren Illinois and ComEd offer a real time pricing (RTP) option for residential customers. A series of hourly prices for electricity are posted one day in advance so that residential consumers who choose this option can determine the best time to operate appliances during the upcoming 24 hours.
- The Illinois Power Agency (IPA) began overseeing the standard offer service power procurement process in 2009. The IPA essentially develops a procurement plan for residential and small commercial customers and conducts a competitive procurement process for that supply. It is also tasked with developing electric generation and co-generation facilities that use indigenous coal or renewable resources financed with bonds issued by the Illinois Financing Authority.[20]

Mandated Rate Reductions

- The Illinois Public Utilities Act amendments mandated rate cuts that were dependent on how many customers the utility served. For utilities serving more than 12,500 customers, rates were reduced 15% relative to 1997 base rates beginning August 1, 1998. For utilities serving more than 500,000 customers, rates were reduced by 5% on May 1, 2002, relative to 1997 base rates. with bundled rates for all customers remaining frozen until January 1, 2007. Alternatively, any utility whose average residential retail rate was less than or equal to that same rate for a group of Midwest Utilities could reduce rates on August 1, 1998 by 5%, and on October 1, 2000 and October 1, 2002 by either 5% or the percentage by which the utility's average residential retail rate exceeded that of the Midwest Utilities.[21]

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[18] Illinois Power Agency Act, Public Act 95-0481, Illinois SB1592, effective August 28, 2007, at 220 ILCS 5/16-113(h). Available at http://www.ilga.gov/legislation/publicacts/fulltext.asp?Name=095-0481
[19] Illinois Commerce Commission, Electric Service Switching. 2013 Filings Updated through March 31, 2013. http://www.icc.illinois.gov/electricity/switchingstatistics.aspx
[20] More information on the IPA available at http://www2.illinois.gov/ipa/Pages/default.aspx
[21] Electric Service Customer Choice and Rate Relief Law of 1997, Public Act 90-0561, Illinois HB 362, at 220 ILCS 5/16-111(b). Available at http://www.ilga.gov/legislation/publicacts/pubact90/acts/90-0561.html

Current Actions at PUC/ISO/RTO/Legislature

- The ICC currently has an open case regarding the "development and adoption of rules concerning municipal aggregation." A proposed order was issued on June 26, 2013.[22]
- The Federal Energy Regulatory Commission has an open docket to address capacity deliverability issues between MISO and PJM. In a presentation to FERC at its June Open Meeting, David Patton, MISO's market monitor noted that MISO experienced "havoc" in the summer of 2012 because of its inability to access capacity resources in PJM due to inefficiencies at the seam.[23]

Divestiture

- In 1999, Illinois Power sold the Clinton nuclear plant to AmerGen, and in 2000, transferred its fossil generation units to an unregulated affiliate. In 1999, ComEd sold its fossil generating capacity (9,772 MW) to Edison Mission Energy, and in 2001, transferred its nuclear generating assets to an unregulated affiliate at market value. In 1999, Central Illinois Public Service spun off, at book value, its Illinois fossil generating units to an unregulated affiliate. In 2002, Central Illinois Light transferred its generation assets to an unregulated affiliate. Central Illinois Public Service, Central Illinois Light, and Illinois Power are now known as Ameren Illinois.[24]

New York

History

- Retail access was implemented in 1998 pursuant to the New York's Public Service Commission's (PSC) 1996 "Competitive Opportunities" order.[25] The PSC did not adopt a generic policy regarding recovery of stranded investment but considered

[22] Case No. 12- 0456; June 26, 2013 proposed order available at http://www.icc.illinois.gov/docket/files.aspx?no=12-0456&docId=200089

[23] FERC Docket No. AD12-16-000; Presentations on this issue were presented to FERC at its June 20, 2013 Open Meeting and are available at http://www.ferc.gov/

[24] SNL Energy, Regulatory Research Associates, Commission Profiles, Illinois, Electric Regulatory Reform/Industry Restructuring. (Updated August 1, 2012)

[25] State of New York Public Service Commission, Opinion No. 96-12 , Cases 94-E-0952, et al. In the Matter of Competitive Opportunities Regarding Electric Service. (May 20, 1996) Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B076F3B08-917D-47FE-83C0-8B2B32822A67%7D

this issue on a company-by company basis.[26] The PSC indicated a preference for, but did not require, divestiture of generation assets.[27]

- The incumbent power distributors have retained the provider-of-last-resort (POLR) obligation,[28] and are procuring the power to meet this obligation through bilateral wholesale contracts with competitive suppliers. Several utilities have physical contracts with non-utility generators that provide a portion of their supply needs. Others have physical contracts with nuclear plants. Most of the utilities physically purchase the majority of their required energy on the New York Independent System Operator (NYISO) Day-ahead market.[29]
- In 1999, the PSC approved a plan to open to competition electric metering services, including installation and maintenance, meter reading, and meter data retrieval and storage.[30]

2012 Annual Average Retail Price

- Residential: 17.62 cents per kWh
- Commercial: 15.03 cents per kWh
- Industrial: 6.68 cents per kWh

Reliability/Capacity Issues

- The Independent Power Producers of New York filed a complaint with FERC about NYISO's reliability must-run arrangements being offered into the entity's installed capacity spot auctions at a "de minimis price" causing the artificial suppression of the market.[31]

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[26] State of New York Public Service Commission, Opinion No. 96-12 , Cases 94-E-0952, et al. In the Matter of Competitive Opportunities Regarding Electric Service, at 55. (May 20, 1996) Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B076F3B08-917D-47FE-83C0-8B2B32822A67%7D

[27] State of New York Public Service Commission, Opinion No. 96-12 , Cases 94-E-0952, et al. In the Matter of Competitive Opportunities Regarding Electric Service, at 65. (May 20, 1996) Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B076F3B08-917D-47FE-83C0-8B2B32822A67%7D

[28] State of New York Public Service Commission, Opinion No. 96-12 , Cases 94-E-0952, et al. In the Matter of Competitive Opportunities Regarding Electric Service, at 73. (May 20, 1996) Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B076F3B08-917D-47FE-83C0-8B2B32822A67%7D

[29] SNL Energy, Regulatory Research Associates, Commission Profiles, New York, Electric Regulatory Reform/Industry Restructuring. (Updated December 3, 2012).

[30] State of New York Public Service Commission, Case 94-E-0952, In the Matter of Competitive Opportunities Regarding Electric Service, Order Providing for Competitive Metering. (June 16, 1999) Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={51479E3C-DAFE-4576-90E2-5411918235D7}

[31] *Independent Power Producers of New York, Inc. v. New York Independent System Operator.* FERC Docket No. EL13-62-000

Treatment of Residential Customers

- Residential consumers can elect to receive service through the regulated tariff of the local electric distribution company, or through an aggregation program, or directly from a competitive retailer known in New York as an energy service company.[32]
- The energy provided to residential and small commercial customers is price-hedged through various financial instruments. The PSC allows the utilities to use a market supply charge to flow through variations in POLR power costs through each customer bill (i.e., monthly or bi-monthly basis).
- As of December 2012, 23.7% of residential customers switched providers.[33]

Mandated Rate Reductions

- Consolidated Edison had a 25% industrial rate reduction for 5 years and 10% for all other customers, phased in over 5 years;
- Central Hudson Gas & Electric had base rates frozen at 1993 levels through June 1, 2001 for all customers; large industrial customers that purchased electricity from Central Hudson received a 5% discount until mid-2001.
- New York State Electric & Gas had rates capped until 2003 and then fixed until 2005, with reductions of 5% for industrial and large customer rates for five years (five reductions of 5% each); residential and small commercial/industrial customers received a 15% reduction by the third year and 5% by the fifth year;
- Niagara Mohawk Power/National Grid's residential and commercial customers received a 3.2% decrease phased in over 3 years. Industrial customers received about a 13% phased rate reduction;
- Orange and Rockland Utilities reduced rates by 4% for residential customers, and by 4-14% for commercial and industrial customers from 1995-1996 with another 1% reduction in 1997 and in 1998 for residential customers and 8.5% reduction in 1997 for large industrial customers;
- Rochester Gas & Electric's rates were set until mid-2002. Residential, commercial, and industrial customers received 7.5%, 8%, and 11.2% rate reductions, respectively, phased in over five years.[34]

Current Actions at PUC/ISO/RTO/Legislature

- In October 2012, the NYPSC staff completed a report that was critical towards retail energy markets, especially as it relates to residential and small non-residential ESCO customer prices compared to full-service utility customers as well as the treatment

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[32] Distributed Energy Financial Group, LLC, 2012 ABACCUS: An Assessment of Restructured Electricity Markets, at 76-77. (December 2012) Available at http://defgllc.com/publication/2012-abaccus-electricity-restructuring-scorecard/

[33] New York Electric Retail Access Migration Data for December 2012. Available at http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/4759ecee7586f24b85257687006f396e/$FILE/Electric%20Migration_12.2012.pdf

[34] Matthew H Brown, Restructuring in Retrospect, National Conference of State Legislatures. (October 2001) Available at http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/restructing_in_retrospect.pdf

of "low-income" customers.[35] This proceeding is ongoing with the latest set of comments filed on March 15, 2013.

Divestiture

- While the PSC indicated a preference for, but did not require, divestiture of generation assets, in 1997 and 1998, the PSC approved company-specific implementation plans, and virtually all generation assets were divested.[36]

Pennsylvania

History

- The Electricity Generation Customer Choice and Competition Act was enacted in December 1996.[37] A pilot phase began in late 1997, and then a phase-in allowed one-third of consumers to join each year.[38]
- After several years the Pennsylvania Public Utility Commission approved a change in default service rates because some consumers were gaming the system by returning to the utility rate for the summer when competitive prices typically rose, making default service rates more attractive. Under the revised system, utilities were able to impose switching restrictions and exit fees (a market based penalty called the "generation rate adjustment") to discourage this gaming.[39]

2012 Annual Average Retail Price

- Residential: 12.83 cents per kWh
- Commercial: 9.37 cents per kWh
- Industrial: 7.24 cents per kWh

Reliability/Capacity Issues

- The PJM Interconnection has a number of pending cases at FERC related to reliability and capacity issues:

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[35] New York Public Service Commission, Case 12-M-0476, "Order Instituting Proceeding and Seeking Comments Regarding the Operation of the Retail Energy Markets in New York State," October 2012. http://www.askpsc.com/askpsc/publication/?PublicationAction=renderPublicationById&PublicationId=7b13a004e260899f3101bab4ad269b69

[36] SNL Energy, Regulatory Research Associates, Commission Profiles, New York, Merger Activity. (Updated June 28, 2013).

[37] The General Assembly of Pennsylvania, HB 1509, adding Chapter 74 to Title 15 of Pennsylvania Consolidated Statutes. (December 3, 1996) Available at http://www.legis.state.pa.us/cfdocs/Legis/LI/uconsCheck.cfm?txtType=DOC&yr=1996&sessInd=0&smthLwInd=0&act=0138. See also Pennsylvania Consolidated Statutes, Title 15, Part I, Chapter 74. Available at http://www.legis.state.pa.us/WU01/LI/LI/CT/HTM/15/00.074..HTM

[38] Pennsylvania Consolidated Statutes, Title 15, Part I, Chapter 74, Section 7405. Available at http://www.legis.state.pa.us/WU01/LI/LI/CT/HTM/15/00.074..HTM

[39] Distributed Energy Financial Group, LLC, 2012 ABACCUS: An Assessment of Restructured Electricity Markets, at 85. (December 2012) Available at http://defgllc.com/publication/2012-abaccus-electricity-restructuring-scorecard/

- PJM uses a minimum offer price rule (MOPR) to prevent suppliers from bidding to sell power at below competitive price levels. However, arguing that the PJM market does not incentivize the building of enough new generation to serve their states, New Jersey and Maryland officials began to develop initiatives to subsidize the construction of new generating capacity. After various FERC orders and subsequent changes to the MOPR, this issue is still ongoing.[40]
- After financial traders discovered advantages of submitting "up-to" bids to hedge their exposure to congestions costs, PJM has asked FERC to approve tariff revisions governing such bids.[41]
- FERC has an open docket to address capacity deliverability issues between MISO and PJM. In a presentation to FERC at its June Open Meeting, the Organization of PJM States and the Organization of MISO States provided joint comments that acknowledge the presence of potential barriers to participation in the MISO and PJM capacity markets, but believe the issue is whether such barriers are appropriate and/or reasonable.[42]

Treatment of Residential Customers

- As of February 2013, only 35% of residential customers have switched to an electric generation supplier.
- As the PUC acknowledged in its February 14, 2013 final order in its Investigation of Pennsylvania's Retail Electricity Market, the current market mechanisms can "inhibit consumers' ability to make informed decisions due to the receipt of false or misleading price signals."[43] The PUC characterized the relationship between the electric generation suppliers and customers as "tenuous at best."[44]

Mandated Rate Reductions

- Pennsylvania's nine utilities each received different treatment with respect to initial rate decreases, the size of stranded cost recovery, and competitive transition charges. For example, transmission and distribution rates were capped for PECO Energy customers through 2006; generation prices were capped through 2010.

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[40] FERC Docket No. ER13-535

[41] FERC Docket No. ER13-1654

[42] FERC Docket No. AD12-16-000; Joint Comments of the Organization of PJM States, Inc. and the Organization of MISO States. http://www.ferc.gov/industries/electric/indus-act/rto/oms-opsi.pdf

[43] February 14, 2013 Final Order at 12. Investigation of Pennsylvania's Retail Electricity Market. Docket No. I-2011-237952. Available at http://www.puc.state.pa.us/utility_industry/electricity/retail_markets_investigation.aspx

[44] February 14, 2013 Final Order at 12. Investigation of Pennsylvania's Retail Electricity Market. Docket No. I-2011-237952. Available at http://www.puc.state.pa.us/utility_industry/electricity/retail_markets_investigation.aspx

PECO's initial restructuring plan provided for recovery of $5.26 billion of stranded costs through a Competition Transition Charge that was in place through 2010.[45]

- In 2009, the PUC approved a post-transition POLR plan under which PECO began procuring the power to meet its post-2010 POLR requirements in 2009.[46] The PUC also approved a price mitigation plan under which customers were given the option of "pre-paying" a portion of the expected increase, beginning in 2009.[47]

Current Actions at PUC/ISO/RTO/Legislature

- In February 2013, the Pennsylvania PUC issued a final order in its Investigation of Pennsylvania's Retail Electricity Market.[48] This investigation began in April 2011, because customers were not switching providers. The "price to compare" offered by the electric distribution companies (EDC) essentially created competition with the electric generation suppliers (EGS) such that customers were remaining with their EDC instead of switching to an EGS. Stakeholders filed comments, the PUC issued Phase 1 and Phase 2 orders directing "retail market enhancements," and the Office of Competitive Market Oversight held a number of technical conferences to create proposals for changing the existing retail electricity market and default service model. The final order proposes a new default service model designed to create a more market based "price to compare." The final order also directs a number of ongoing working groups and follow up items for the Office of Competitive Market Oversight related to consumer education, consolidated billing, procurement methodology, and alternative providers of default service.[49]
- Since the PUC began its Investigation of Pennsylvania's Retail Electricity Market in 2011, there have been seven separate orders attempting to address various aspects of retail electric service.[50]
- POLR is also an issue of ongoing regulation at the PUC. Most recently, a plan was approved on Aug. 12, 2012, for FirstEnergy subsidiaries Metropolitan Edison, Pennsylvania Electric, Pennsylvania Power, and West Penn Power, covering the June

[45] Pennsylvania Public Utilities Commission, Final Order, Docket Nos. R-00973953 and P-00971265. (May 14, 1998). Available at http://www.puc.state.pa.us//pcdocs/1236161.pdf

[46] SNL Energy, Regulatory Research Associates, Commission Profiles, Pennsylvania, Electric Regulatory Reform/Industry Restructuring. (Updated February 20, 2013)

[47]Pennsylvania Public Utility Commission, March 12, 2009 Order, Docket No. P-2008-2062741. Available at http://www.puc.state.pa.us//pcdocs/1035837.rtf; Pennsylvania Public Utility Commission, Press Release, PUC Approves PECO Voluntary Market Rate Transition Phase-In Plan. (March 12, 2009) Available at http://www.puc.state.pa.us//pcdocs/1038702.doc

[48] February 14, 2013 Final Order. Investigation of Pennsylvania's Retail Electricity Market. Docket No. I-2011-237952. Available at http://www.puc.state.pa.us/utility_industry/electricity/retail_markets_investigation.aspx

[49] Pennsylvania PUC Retail Markets Investigation. http://www.puc.pa.gov/utility_industry/electricity/retail_markets_investigation.aspx

[50] Pennsylvania PUC Electric Competitive Market Oversight http://www.puc.state.pa.us/utility_industry/electricity/electric_competitive_market_oversight.aspx

1, 2013-to-May 31, 2015 period, calling for the power to meet POLR requirements to be procured as follows: for residential customers, 45% is to come from 12-month fixed price full requirements contracts, 45% from 24-month fixed price full requirements contracts, and 10% from the spot market; for commercial customers, 90% under 12-month, fixed price full requirements contracts and 10% under six-month fixed price full requirements contracts; and, industrial, 100% through the hourly-priced spot market.[51]

Divestiture

- PECO was permitted to issue $4 billion in asset securitization bonds and to transfer its generation assets to a separate affiliate.[52]

Maryland

History

- The Electric Customer Choice and Competition Act of 1999 was adopted in April 1999. While the Act allowed for a three year phase-in approach, the Public Service Commission (PSC) allowed customers of the investor-owned utilities to be eligible for choice on July 1, 2000 and customers of electric cooperatives to be eligible at the end of 2001.[53]
- The Act also mandated rate reductions of 3-7.5% as of June 30, 1999 with rates frozen for four years but authorized the PSC to determine the actual amount of the rate reductions and the rate freeze for each utility.[54]
- In 2007, legislation was enacted that requires the PSC to submit a retail competition status report every five years beginning at year end 2008, in order to determine the need for the continuation of the provision of standard offer service/default service.[55]
- In February 2009, the Maryland State Finance Committee introduced Senate Bill 795, the "Maryland Electricity Reregulation and Energy Independence Act of 2009" with the support of the governor. The bill stated that competitive retail electric

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[51] SNL Energy, Regulatory Research Associates, Commission Profiles, Pennsylvania, Electric Regulatory Reform/Industry Restructuring. (Updated February 20, 2013)

[52] Pennsylvania Public Utilities Commission, Final Order, Docket Nos. R-00973953 and P-00971265. (May 14, 1998). Available at http://www.puc.state.pa.us//pcdocs/1236161.pdf

[53] SB300 and HB703, The Electric Customer Choice and Competition Act of 1999, Md. Public Utilities Code Ann., Division I. Public Utilities, Title 7, Subtitle 5. Electric Industry Restructuring. (2000). Available at http://mgaleg.maryland.gov/webmga/frmStatutesText.aspx?article=gpu&section=7-501&ext=html&session=2013RS&tab=subject5

[54] Md. Public Utilities Code Ann. §7-505(d). Available at http://mgaleg.maryland.gov/webmga/frmStatutesText.aspx?article=gpu&section=7-505&ext=html&session=2013RS&tab=subject5

[55] Maryland General Assembly, 2007 Regular Session, Senate Bill 400. Available at http://mgaleg.maryland.gov/webmga/frmMain.aspx?tab=subject3&ys=2007rs/billfile/sb0400.htm

markets did not develop as envisioned. In April, Maryland's House Economic Matters Committee voted nearly unanimously to kill the bill. The following year, the Governor indicated that he would not submit legislation to re-regulate energy markets in the upcoming legislative session but would instead rely on the PSC to use existing authority to build new power generation as needed.

- Five municipal utilities remain locally controlled and are not required to offer retail choice.

2012 Annual Average Retail Price

- Residential: 12.84 cents/kWh
- Commercial: 10.52 cents/kWh
- Industrial: 8.135 cents/kWh

Reliability/Capacity Issues

- In December 2008, the PSC issued its first report under Senate Bill 400.[56] The report stated that the costs, risks and disruption of returning to full cost-of-service regulation would be too great but that the PSC recommends forward-looking re-regulation to ensure a reliable supply of electricity; that Maryland would face real reliability challenges in 2010-2011; and that it would investigate whether and on what terms to build additional generation in Maryland.[57]
- Subsequently, in August 2008, in Case No. 9149, the PSC directed the investor-owned electric utilities to issue requests for proposals to fill potential "gaps" in the supply of electricity.[58]
- In September 2009, the PSC opened "The Matter of Whether New Generating Facilities are Needed to Meet Long-Term Demand for Standard Offer Service" [59] which eventually led to the PSC ordering Baltimore Gas and Electric Company, Potomac Electric Power Company, and Delmarva Power & Light Company to enter into a contract with Competitive Power Ventures in April 2012 to build a 661MW

[56] Maryland Public Service Commission, Final Report Under Senate Bill 400: Options for Re-Regulation and New Generation (December 16, 2008) Available at http://webapp.psc.state.md.us/intranet/sitesearch/MD%20PSC%20Slide%20Presentation_12.16.08_Re%20SB%20400%20Final%20Report.pdf

[57] Maryland Public Service Commission, Final Report Under Senate Bill 400: Options for Re-Regulation and New Generation (December 16, 2008) Available at http://webapp.psc.state.md.us/intranet/sitesearch/MD%20PSC%20Slide%20Presentation_12.16.08_Re%20SB%20400%20Final%20Report.pdf

[58] Maryland Public Service Commission, Case No. 9149, In the Matter of the Investigation of the Process and Criteria for Use in Development of Request for Proposal by the Maryland Investor-Owned Utilities for New Generation to Alleviate Potential Short-Term Reliability Problems in the State of Maryland, initiated on August 8, 2008.

[59] Maryland Public Service Commission, Order No. 82936, Case No. 9214, The Matter of Whether New Generating Facilities are Needed to Meet Long-Term Demand for Standard Offer Service. (September 29, 2009)

natural gas combined-cycle power plant.[60] Exelon and Constellation had agreed to build a 120MW combustion turbine as part of their merger deal.[61]

Treatment of Residential Customers

- As of July 2012, there is 22.1% residential switching in Maryland.[62]
- Utilities were required to provide standard offer service to customers who did not select an alternative provider throughout company-specific transition periods established by the PSC.[63]
  - Standard offer service design and rate levels have been a point of contention. Under the Electric Customer Choice and Competition Act, standard offer service was to remain in effect until July 1, 2003. In Case No. 8908, the PSC determined that "Maryland's electric supply market is not competitive" and that standard offer service must be extended, with standard offer service remaining in effect from 2004 to 2008.[64] Currently, Maryland's investor-owned utilities continue to file standard offer service tariffs.[65]

Mandated Rate Reductions

- Under PSC settlements:
  - Delmarva residential customers received a 7.5% rate reduction and rates were frozen for four years, through June 30, 2004. A 2002 merger-related PSC order extended the rate cap to June 1, 2006.
  - Potomac Electric Power Company residential customers' rates were initially capped through July 1, 2003 at rates effective June 30, 2000. A subsequent settlement reduced residential rates by 3% relative to 1999 revenues.
  - Potomac Edison Company residential customers received a 7% rate reduction, effective January 1, 2002 and rates were frozen through 2008.
  - Baltimore Gas & Electric Company residential customers received a rate reduction of 6.5% and rates were frozen through June 30, 2006.

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[60] Maryland Public Service Commission, Order No. 84815, Case No. 9214 (April 12, 2012); See also Tom Johnson, *In Search of New Generation, MD's Struggles Mirror NJ's*, NJSpotlight. (April 13, 2012) Available at http://www.njspotlight.com/stories/12/0412/2016/

[61] Distributed Energy Financial Group, LLC, 2012 ABACCUS: An Assessment of Restructured Electricity Markets, at 64. (December 2012) Available at http://defgllc.com/publication/2012-abaccus-electricity-restructuring-scorecard/

[62] Distributed Energy Financial Group, LLC, 2012 ABACCUS: An Assessment of Restructured Electricity Markets, at 65. (December 2012) Available at http://defgllc.com/publication/2012-abaccus-electricity-restructuring-scorecard/

[63] SNL Energy, Regulatory Research Associates, Commission Profiles, Maryland, Electric Regulatory Reform/Industry Restructuring. (Updated November 19, 2012)

[64] Maryland Public Service Commission, Order 78400, Case No. 8908, The Matter of the Commission's Inquiry into the Competitive Selection of Electric Suppliers Standard Offer Service. (April 29, 2003)

[65] *See* Maryland Public Service Commission, Case No. 8908, The Matter of the Commission's Inquiry into the Competitive Selection of Electric Suppliers Standard Offer Service.

- As rate caps were scheduled to expire, anticipated price increases resulted in numerous alternative rate mitigation proposals. For example, in anticipation of 72% rate increases in the BGE service territory, the legislature considered bills in 2005 and 2006 to limit the immediate increase to 5% to 25%, with future recovery of deferred costs through a new transition charge. The PSC limited the utilities' rate increases to 15%-15.7% following the expiration of their rate caps.

Current Actions at PUC/ISO/RTO/Legislature

- The PJM Interconnection has a number of pending cases at FERC related to reliability and capacity issues:
  - PJM uses a minimum offer price rule (MOPR) to prevent suppliers from bidding to sell power at below competitive price levels. However, arguing that the PJM market does not incentivize the building of enough new generation to serve their states, New Jersey and Maryland officials began to develop initiatives to subsidize the construction of new generating capacity. After various FERC orders and subsequent changes to the MOPR, this issue is still ongoing.[66]
  - After financial traders discovered advantages of submitting "up-to" bids to hedge their exposure to congestions costs, PJM has asked FERC to approve tariff revisions governing such bids.[67]
  - FERC has an open docket to address capacity deliverability issues between MISO and PJM. In a presentation to FERC at its June Open Meeting, the Organization of PJM States and the Organization of MISO States provided joint comments that acknowledge the presence of potential barriers to participation in the MISO and PJM capacity markets, but believe the issue is whether such barriers are appropriate and/or reasonable.[68]

Divestiture

- The 1999 Act stated that the PSC could not require the utilities to divest of their generation assets but permitted the utilities to seek recovery of transition costs (stranded costs) related to divested generation assets and other costs associated with restructuring.[69]
  - Baltimore Gas & Electric Company was authorized to recover $528 million of stranded costs through a CTC that was in place until June 2006. BGE transferred its generation assets to unregulated affiliates at book value.

[66] FERC Docket No. ER13-535

[67] FERC Docket No. ER13-1654

[68] FERC Docket No. AD12-16-000; Joint Comments of the Organization of PJM States, Inc. and the Organization of MISO States. http://www.ferc.gov/industries/electric/indus-act/rto/oms-opsi.pdf

[69] Md. Public Utilities Code Ann. §7-505(b)(9) and §7-513. Available at http://mgaleg.maryland.gov/webmga/frmStatutesText.aspx?article=gpu&section=7-505&ext=html&session=2013RS&tab=subject5

- Delmarva's Maryland-jurisdictional stranded costs were quantified at $16 million, of which they were allowed to recover $8 million over the July 2000 – June 2003 period through a CTC paid by non-residential customers.
- Potomac Edison Company received no explicit CTC in its restructuring agreement. The company transferred its generation assets to a non-regulated affiliate at book value and entered into a contract with the affiliate to obtain the power to meet its Standard Offer Service obligations at prices that conformed to the rate caps.[70]

Connecticut

History

- Electric restructuring legislation enacted in April 1998, provided for full retail competition to be phased in by July 1, 2000.[71]
- The 1998 legislation required divestiture of nuclear assets and voluntary divestiture of non-nuclear assets, participation in an ISO, functional unbundling, a renewable portfolio standard, 10% rate reduction below December 31, 1996 rates and a rate cap until 2000.[72]
- Initially, few competitive retailers entered the state and the PUC instituted a 12 month switching moratorium to restrict switching back to standard offer service.[73]
- In 2003, due in large part to the lack of customer switching, legislation extended the requirement that utilities provide standard offer service to small and medium-sized customers through December 31, 2006 at a rate that could not exceed December 31, 1996 rates.[74]
- Since January 1, 2007, the utilities have been required to provide standard service to residential customers and small- and medium-sized business customers (customers with maximum demand less than 500 kW) who do not receive power from a competitive supplier and "last-resort" service to larger customers.[75]

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[70] SNL Energy, Regulatory Research Associates, Commission Profiles, Maryland, Electric Regulatory Reform/Industry Restructuring. (Updated November 19, 2012)

[71] Connecticut General Assembly, Substitute HB 5005, Public Act No. 98-28, An Act Concerning Electric Restructuring. (April 1998) Available at http://www.cga.ct.gov/ps98/Act/pa/1998PA-00028-R00HB-05005-PA.htm.

[72] *Id.*

[73] Distributed Energy Financial Group, LLC, 2012 ABACCUS: An Assessment of Restructured Electricity Markets at 51 (December 2012). Available at http://defgllc.com/publication/2012-abaccus-electricity-restructuring-scorecard/

[74] Connecticut General Assembly, Substitute SB 733, Public Act No. 03-135, An Act Concerning Revisions to the Electric Restructuring Legislation. (July 1, 2003) Available at http://www.cga.ct.gov/2003/act/Pa/2003PA-00135-R00SB-00733-PA.htm; *See also* SNL Regulatory Research Associates, Regulatory Focus – Electric Industry Restructuring, August 1, 2012.

[75] SNL Regulatory Research Associates, Regulatory Focus – Electric Industry Restructuring, August 1, 2012.

- Connecticut has six municipal utilities that serve about 5% of the customers in the state. The municipal electric utilities are allowed, but not required, to open their territories to competition and, to date, none have done so.[76]

2012 Annual Average Retail Price

- Residential – 17.375 cents/kWh
- Commercial - 14.7025 cents/kWh
- Industrial – 12.77 cents/kWh

Reliability/Capacity Issues

- 2007 legislation allowed utilities to construct regulated peaking units and ordered the PUC to conduct a proceeding "to assess ways in which the state can ensure and enhance the reliability of electric generating facilities located in the state during periods of peak electric demand."[77]
- Until 2011, resource procurement was based on a "laddering" approach – quarterly bids for tranches of approximately 10% of load for two largest utilities to cover standard offer and last resort service. Legislation enacted in 2011 requires the procurement manager at the Department of Environmental Protection, in consultation with each electric distribution company, to develop a plan for procuring power and related products "that will enable each electric distribution company to manage a portfolio of contracts to reduce the average cost of standard service while maintaining standard cost volatility within reasonable levels." Contracts of varying term lengths may be approved.[78]

Treatment of Residential Customers

- 44.1% of residential customers have switched as of September 2012.[79]
- Utilities were initially required to provide standard offer service to small and medium-sized customers through December 31, 2006.

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[76] Connecticut Office of Legislative Research, Status and Impact of Electric Competition, 2011-R-0274. (October 4, 2011) Available at http://www.cga.ct.gov/2011/rpt/2011-R-0274.htm.

[77] Connecticut General Assembly, HB 7432, Public Law No. 07-242, An Act Concerning Electricity and Energy Efficiency. (July 1, 2007) Available at http://www.cga.ct.gov/2007/ACT/PA/2007PA-00242-R00HB-07432-PA.htm.

[78] Connecticut General Assembly, SB 1243, Public Act No. 11-80, An Act Concerning the Establishment of the Department of Energy and Environmental Protection And Planning for Connecticut's Energy Future. (July 1, 2011) Available at http://www.cga.ct.gov/2011/act/pa/2011PA-00080-R00SB-01243-PA.htm.

[79] Distributed Energy Financial Group, LLC, 2012 ABACCUS: An Assessment of Restructured Electricity Markets, at 53. (December 2012). Available at http://defgllc.com/publication/2012-abaccus-electricity-restructuring-scorecard/

Mandated Rate Reductions

- 1998 legislation required a 10% rate reduction below December 31, 1996 rates and a rate cap. The rate cap began in 1998 and was initially set to expire in 2000.[80] As a result of the 2003 legislation, the rate cap was extended to December 31, 2006.[81]

Current Actions at PUC/ISO/RTO/Legislature

- In late 2010, ISO New England launched a major Strategic Planning Initiative to address concerns about resource performance and New England's increased reliance on natural gas for electric generation. An outcome of such reliance on natural gas is that gas pipeline transportation constraints are common and the region must rely on aging oil- and coal-fired generators to maintain reliability during peak demand periods or when the gas pipeline system is limited. Since the fall of 2012, the ISO and stakeholders have been developing short- and long-term solutions to mitigate the risks related to generator resource performance.[82]

Divestiture

- The 1998 Act Concerning Electric Restructuring required divestiture of nuclear assets and voluntary divestiture of non-nuclear assets.[83]

New Jersey

History

- In February 1999, the Electric Discount and Energy Competition Act was signed into law allowing the Board of Public Utilities (BPU) to require the State's electric utilities to divest themselves of their electric generation assets; mandating a reduction in electricity rates for a period of four years; permitting competition in the electric and gas marketplace; and allowing recovery of stranded costs through a non-bypassable market transition charge.[84]
- By 2002, competition in the electric and gas marketplace had not developed as anticipated and the market cost of electricity had not declined below the mandated rates. The BPU projected that the difference between the market cost and mandated

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[80] Connecticut General Assembly, Substitute HB 5005, Public Act No. 98-28, An Act Concerning Electric Restructuring. (April 1998) Available at http://www.cga.ct.gov/ps98/Act/pa/1998PA-00028-R00HB-05005-PA.htm

[81] Connecticut General Assembly, Substitute SB 733, Public Act No. 03-135, An Act Concerning Revisions to the Electric Restructuring Legislation. (July 1, 2003) Available at http://www.cga.ct.gov/2003/act/Pa/2003PA-00135-R00SB-00733-PA.htm

[82] ISO New England 2013 Regional Electricity Outlook, http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/2013_reo.pdf.

[83] Connecticut General Assembly, Substitute HB 5005, Public Act No. 98-28, An Act Concerning Electric Restructuring. (April 1998) Available at http://www.cga.ct.gov/ps98/Act/pa/1998PA-00028-R00HB-05005-PA.htm.

[84] State of New Jersey, 208th Legislature, Electric Discount and Energy Competition Act (February 1999). Available at http://www.njleg.state.nj.us/9899/Bills/s0500/7_i1.pdf

rates, known as the "deferred balances," accumulated to approximately $1 billion dollars. Pursuant to Executive Order #25, and pursuant to the Electric Discount and Energy Competition Act, the electric utilities were permitted to recover the difference or deferred costs.[85]

2012 Annual Average Retail Price

- Residential: 15.77 cents per kWh
- Commercial: 12.78 cents per kWh
- Industrial: 10.53 cents per kWh

Reliability/Capacity Issues

- In New Jersey, there is too much congestion on the power grid and not enough capacity. New Jersey's efforts to create incentives for new power plants have been hampered by rules adopted by the PJM Interconnection, making it difficult for three power plants currently under contract to qualify for the ratepayer subsidies needed to help make the units profitable.[86]

Treatment of Residential Customers

- The 1999 law required the incumbent electric distribution companies (EDCs) to provide basic generation service (BGS) at capped rates through July 31, 2003, for customers who declined to select an alternative generation supplier. In 2002, the BPU approved a multi-period wholesale auction process for BGS beginning Aug. 1, 2003.[87]
- BGS prices now reflect a blend of one-, two- and three-year contracts, with one-third of the load being bid out on an annual basis under a three-year contract with the remaining load served by previously executed contracts.[88]
- As of August 2012, 14.3% of residential customers switched providers.[89]

Mandated Rate Reductions

- The BPU approved company-specific transition plans that required the utilities to phase in, by August 2002, 10% minimum rate reductions, after which rates were capped at the reduced levels through July 2003.[90]

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[85] State of New Jersey, Executive Order #25, Governor James E. McGreevey. (August 12, 2002) Available at http://nj.gov/infobank/circular/eom25.htm

[86] Tom Johnson, *In Search of New Generation, MD's Struggles Mirror NJ's*, NJSpotlight. (April 13, 2012) Available at http://www.njspotlight.com/stories/12/0412/2016/

[87] SNL Energy, Regulatory Research Associates, Commission Profiles, New Jersey, Electric Regulatory Reform/Industry Restructuring. (Updated March 20, 2013)

[88] SNL Energy, Regulatory Research Associates, Commission Profiles, New Jersey, Electric Regulatory Reform/Industry Restructuring. (Updated March 20, 2013)

[89] Distributed Energy Financial Group, LLC, 2012 ABACCUS: An Assessment of Restructured Electricity Markets, at 76 (December 2012). Available at http://defgllc.com/publication/2012-abaccus-electricity-restructuring-scorecard/

[90] State of New Jersey, 208th Legislature, Electric Discount and Energy Competition Act (February 1999). Available at http://www.njleg.state.nj.us/9899/Bills/s0500/7_i1.pdf

Current Actions at PUC/ISO/RTO/Legislature

- The PJM Interconnection has a number of pending cases at FERC related to reliability and capacity issues:
  - PJM uses a minimum offer price rule (MOPR) to prevent suppliers from bidding to sell power at below competitive price levels. However, arguing that the PJM market does not incentivize the building of enough new generation to serve their states, New Jersey and Maryland officials began to develop initiatives to subsidize the construction of new generating capacity. After various FERC orders and subsequent changes to the MOPR, this issue is still ongoing.[91]
  - After financial traders discovered advantages of submitting "up-to" bids to hedge their exposure to congestions costs, PJM has asked FERC to approve tariff revisions governing such bids.[92]
  - FERC has an open docket to address capacity deliverability issues between MISO and PJM. In a presentation to FERC at its June Open Meeting, the Organization of PJM States and the Organization of MISO States provided joint comments that acknowledge the presence of potential barriers to participation in the MISO and PJM capacity markets, but believe the issue is whether such barriers are appropriate and/or reasonable.[93]

Divestiture

- Public Service Electric and Gas was authorized to recover $2.94 billion of generation-related stranded costs, with up to $2.4 billion to be securitized. PSEG transferred its generating assets to affiliate PSEG Power at market value.
- Jersey Central Power & Light divested its generation assets. The company was authorized to recover, through a market transition charge: above-market non-utility generator (NUG) contract costs; under-recovered fuel balances; and, approximately $600 million of sunk Oyster Creek nuclear plant costs ($320 million was securitized). JCPL continues to defer unrecovered NUG costs, with interest on the deferrals, through the terms of the contracts.
- Atlantic City Electric (ACE) was authorized to recover NUG-related stranded costs over the terms of the contracts through an NUG transition charge. ACE was authorized to fully recover stranded costs associated with divested generating facilities, and to securitize net stranded costs associated with divested plants and NUG contracts.

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[91] FERC Docket No. ER13-535

[92] FERC Docket No. ER13-1654

[93] FERC Docket No. AD12-16-000; Joint Comments of the Organization of PJM States, Inc. and the Organization of MISO States. http://www.ferc.gov/industries/electric/indus-act/rto/oms-opsi.pdf

- Rockland Electric (RE) did not own generation assets, and was authorized to recover above-market NUG contract costs over the terms of the contracts. [94]

Maine

History

- In May 1997, the Maine Legislature passed Directive 1804 to require divestiture of utility generation assets and initiate retail choice for all customers in March 2000.[95] The law also imposed a 33% market share cap on investor-owned utilities in their old service areas.[96]
- Standard Offer Service is available to all customers and is procured and priced through a competitive bid process run by the Maine Public Utilities Commission. The utilities are not permitted to bid to provide Standard Offer Service, and affiliates may not provide more than 20% of Standard Offer Service in a transmission and distribution utility's service territory.[97]

2012 Annual Average Retail Price

- Residential: 14.71cents per kWh
- Commercial: 11.59 cents per kWh
- Industrial: 7.87 cents per kWh

Reliability/Capacity Issues

- None

Treatment of Residential Customers:

- In late 2004, an auction produced standard offer rates with a nearly 30% increase in the generation price due to conditions in the wholesale market. In more recent auctions, the Commission utilizes a "laddering" structure for Standard Offer Service procurement for residential and small commercial customers. Under the laddered approach, the MPUC goes to the market each year for one-third of the load in a three-year contract.[98]

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[94] SNL Energy, Regulatory Research Associates, Commission Profiles, New Jersey, Electric Regulatory Reform/Industry Restructuring. (Updated March 20, 2013)

[95] Directive 1804 codified at Maine Revised Statutes, Title 35-A, Chapter 32: Electric Industry Restructuring. Available at http://www.mainelegislature.org/legis/statutes/35-a/title35-Ach32.pdf

[96] Maine Revised Statutes, Title 35-A, Chapter 32, Section 3205(2)(B). Available at http://www.mainelegislature.org/legis/statutes/35-a/title35-Ach32.pdf.

[97] Maine Revised Statutes, Title 35-A, Chapter 32, Section 3212. Available at http://www.mainelegislature.org/legis/statutes/35-a/title35-Ach32.pdf; See also Maine Public Utilities Commission Electricity Rules, Chapter 301 – Standard Offer Service. Available at http://www.maine.gov/sos/cec/rules/65/407/407c301.doc

[98] SNL Energy, Regulatory Research Associates, Commission Profiles, Maine, Electric Regulatory Reform/Industry Restructuring (Updated February 4, 2013).

- As of May 2013, 28.9% of "small" customers are enrolled with a Competitive Energy Provider, representing 34.3% of residential and small commercial load in Maine.[99] The Residential/Small Commercial customer class is defined as customers with demand of:
  - <25 kW in Bangor Hydro-Electric Company service territory
  - <20 kW in Central Maine Power Company service territory
  - <50 kW in Maine Public Service Company service territory.[100]

Mandated Rate Reductions

- No rate reductions were mandated. However, in 1999, Central Maine Power sold its hydro, fossil, and biomass power plants, totaling 1,185 MW (book value of $217 million), to FPL Group for approximately $850 million. Approximately $483 million of "added value" from the sale was available to mitigate stranded costs and reduce rates.[101]

Current Actions at PUC/ISO/RTO/Legislature

- On June 11, 2013, the MPUC issued a request for proposals for electric Standard Offer Service for Commercial and Industrial Customers.[102]

Divestiture

- Investor-owned utilities were required to submit a plan to divest of their generation to the Maine PSC by January 1, 1999. Utilities were not required to divest nuclear generation or generation outside of the United States.[103]
- In 1999, Bangor Hydro-Electric Company sold most of its generation assets (89.2 MW) and certain transmission rights to a subsidiary of PPL Corporation, for $89 million.
- In 1999, Central Maine Power sold its hydro, fossil, and biomass power plants, totaling 1,185 MW (book value of $217 million), to FPL Group for approximately $850 million.
- In 1999, Maine Public Service Company sold its generating assets (92 MW), which included fossil and hydro generation and 18 MW of purchased power agreements, to a subsidiary of WPS Resources, for $37.5 million, or 3.2 times net book value.[104]

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[99] Maine Public Utilities Commission Migration Statitistics. (May 2013) Available at http://www.maine.gov/mpuc/electricity/choosing_supplier/migration_statistics.shtml

[100] *Id.*

[101] SNL Energy, Regulatory Research Associates, Commission Profiles, Maine, Electric Regulatory Reform/Industry Restructuring (Updated February 4, 2013).

[102] Maine Public Utilities Commission, Standard Offer Solicitations. Available at http://www.maine.gov/mpuc/electricity/rfps/so_solicitations.shtml

[103] Maine Revised Statutes, Title 35-A, Chapter 32, Section 3204. Available at http://www.mainelegislature.org/legis/statutes/35-a/title35-Ach32.pdf

[104] SNL Energy, Regulatory Research Associates, Commission Profiles, Maine, Electric Regulatory Reform/Industry Restructuring (Updated February 4, 2013).

Massachusetts

History

- One of the early adopters of electric restructuring, Massachusetts enacted legislation in November 1997, with retail competition for all customers beginning on March 1, 1998. With the advent of competition, rate cuts of 10% were implemented at first, and another 5% after 18 months.[105]
- In 1998, the Department of Public Utilities (DPU) issued final decisions and regulations to open the electricity market to retail competition.[106]
- Generation service became competitive, but transmission, distribution and customer services remained regulated monopoly services. Standard offer service was created as a transitional service for existing electricity customers. The standard offer was set at 2.8 cents with a trajectory to rise to 5.2 cents per kWh in 2005 (projected to be above market in 2005). These were administratively determined numbers (not market based) and included fuel triggers to increase if necessary.[107]
- The initial 2.8 cents per kWh standard offer service rate was found to be too low for competitors, stifling competition until the standard offer service rate was scheduled to rise in 1999. In 2000, standard offer rates were increased in response to market price increases.[108]
- In August 2012, Governor Patrick signed S. 2395, "An Act Relative to Competitively Priced Electricity in the Commonwealth" intended to "protect ratepayers while providing greater reliability and energy independence." The bill, amongst other things, establishes an energy policy review commission and tasks it with reporting to the legislature on the structure of the regional wholesale electricity market and its impact on electricity costs.[109]

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[105] The General Court of the Commonwealth of Massachusetts, An Act Relative to Restructuring the Electric Utility Industry in the Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Consumer Protections, Chapter 164 of the Acts of 1997, HB 5117 (1997). Available at https://malegislature.gov/Laws/SessionLaws/Acts/1997/Chapter164.

[106] Massachusetts Department of Public Utilities, Rules Governing the Restructuring of the Electric Industry, 220 CMR 11.00 (February 20, 1998). Available at http://www.env.state.ma.us/dpu/docs/restruct/96-100/cmr11-2.pdf

[107] Distributed Energy Financial Group, LLC, 2012 ABACCUS: An Assessment of Restructured Electricity Markets, at 66 (December 2012). Available at http://defgllc.com/publication/2012-abaccus-electricity-restructuring-scorecard/

[108] *Id.*

[109] General Court of the Commonwealth of Massachusetts, Bill S.2395, An Act Relative to Competitively Priced Electricity in the Commonwealth (August 3, 2012). Available at https://malegislature.gov/Bills/187/Senate/S02395; *See also* Governor Patrick Signs Energy Bill, Press Release (August 3, 2012). Available at http://www.mass.gov/governor/pressoffice/pressreleases/2012/2012803-governor-patrick-signs-energy-bill.html;

2012 Annual Average Retail Price

- Residential – 14.96 cents/kWh
- Commercial – 13.96 cents/kWh
- Industrial – 12.89 cents/kWh

Reliability/Capacity Issues

- S. 2395 required the DPU to investigate whether there is a need for additional capacity resources in the Northeast Massachusetts/Greater Boston area over the next ten years and if so, whether the DPU should order the distribution companies serving that area to solicit proposals and enter into long-term contracts for generation resources for the area.[110]
- The DPU issued an order on March 15, 2013, in response to the 2012 law, finding that sufficient resources exist assuming that a proposed 674 MW natural gas plant gets built. Without such plant, the DPU found there would be a need for additional capacity in the area within the next ten years. The DPU order also recognized that the ISO New England Forward Capacity Market has suffered problems that the ISO and stakeholders continue to address.[111]

Treatment of Residential Customers

- 14.3% of residential customers have switched as of June 2012.
- As of 2005, standard offer service expired. These customers were transferred to default service which had been designed for customers who were new to the system but had not selected a competitive service provider. (In Massachusetts, "standard offer" and "default service" have distinct meanings.) Default service is provided by third party suppliers through a competitive bid process.[112]
- Municipalities may aggregate the load of interested consumers within their boundaries.[113]
- Aggregation is active on Cape Cod (eastern MA) with the Cape Light Compact serving a significant number of customers. Cape Light accounts for approximately

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[110] General Court of the Commonwealth of Massachusetts, Bill S.2395, An Act Relative to Competitively Priced Electricity in the Commonwealth, Section 40 (August 3, 2012). Available at https://malegislature.gov/Bills/187/Senate/S02395

[111] ISO Newswire "Massachusetts DPU issues order on capacity needs in Boston area" (March 27, 2013) http://isonewswire.com/updates/2013/3/27/massachusetts-dpu-issues-order-on-capacity-needs-in-boston-a.html.

[112] SNL Energy, Regulatory Research Associates, Commission Profiles, Massachusetts, Electric Regulatory Reform/Industry Restructuring (Updated April 9, 2013).

[113] The General Court of the Commonwealth of Massachusetts, An Act Relative to Restructuring the Electric Utility Industry in the Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Consumer Protections, Chapter 164 of the Acts of 1997, HB 5117, Section 247 adding Section 134 to Chapter 164 (1997). Available at https://malegislature.gov/Laws/SessionLaws/Acts/1997/Chapter164

one-half of the residential customer switching in Massachusetts. Customers who do not wish to participate can opt out of the aggregation program.[114]

Mandated Rate Reductions

- Consumer electricity rates were required to be reduced by at least 10% beginning on March 1, 1998, as part of an aggregate rate reduction totaling at least 15%.

Current Actions at PUC/ISO/RTO/Legislature

- In late 2010, ISO New England launched a major Strategic Planning Initiative to address concerns about resource performance and New England's increased reliance on natural gas for electric generation. An outcome of such reliance on natural gas is that gas pipeline transportation constraints are common and the region must rely on aging oil- and coal-fired generators to maintain reliability during peak demand periods or when the gas pipeline system is limited. Since the fall of 2012, the ISO and stakeholders have been developing short- and long-term solutions to mitigate the risks related to generator resource performance.[115]

Divestiture

- Divestiture of non-nuclear generation facilities was not mandated, but recovery of stranded costs and the use of securitization were permitted only if a utility divested its generation facilities.[116] As a result, between 1997 and 1999, virtually all generation assets were ultimately divested through company-specific plans approved by the DPU.[117]

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[114] Massachusetts Department of Public Utilities, Municipal Aggregation. Available at http://www.mass.gov/eea/energy-utilities-clean-tech/electric-power/electric-market-info/electric-industry-restructuring/restructuring-issues/municipal-aggregation.html (For example, see *Petition of Towns of Aquinnah, Barnstable, Bourne, Brewster, Chatham, Chilmark, Dennis, Eastham, Edgartown, Falmouth, Harwich, Mashpee, Oak Bluffs, Orleans, Provincetown, Sandwich, Tisbury, Truro, Wellfleet, West Tisbury, Yarmouth, and the Counties of Barnstable and Dukes, acting together as the Cape Light Compact, for approval pursuant to G.L. c. 164, § 134, to enter into a competitive electric supply agreement as an opt-out municipal aggregator*, Massachusetts Department of Telecommunications and Energy Case 04-32, May 4, 2004 Order. Available at http://www.env.state.ma.us/dpu/docs/electric/04-32/54order.pdf)

[115] ISO New England 2013 Regional Electricity Outlook, http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/2013_reo.pdf.

[116] The General Court of the Commonwealth of Massachusetts, An Act Relative to Restructuring the Electric Utility Industry in the Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Consumer Protections, Chapter 164 of the Acts of 1997, HB 5117, (1997). Available at https://malegislature.gov/Laws/SessionLaws/Acts/1997/Chapter164; SNL Energy, Regulatory Research Associates, Commission Profiles, Massachusetts, Electric Regulatory Reform/Industry Restructuring (Updated April 9, 2013).

[117] Massachusetts Department of Public Utilities, Electric Company Restructuring Proceedings. Available at http://www.mass.gov/eea/energy-utilities-clean-tech/electric-power/electric-market-info/electric-industry-restructuring/restructuring-issues/electric-restruturing-proceedings/; SNL Energy, Regulatory Research Associates, Commission Profiles, Massachusetts, Electric Regulatory Reform/Industry Restructuring (Updated April 9, 2013).

Ohio

History

- Retail competition began January 1, 2001, pursuant to Senate Bill 3, which was enacted in 1999.[118] The bill established a market development period (MDP) that extended through 2005, with a 5% residential generation-related rate reduction, and all other rate components to be frozen through the MDP. Stranded cost recovery extended to at least year-end 2005 for generation-related assets, and to year-end 2010 for regulatory assets. [119]
- Ohio's law allowed communities to aggregate.[120] Between 2008 and 2010, the number of residential consumers participating in aggregation programs rose from 202,000 to 910,000 such that nearly one quarter of the state's residential consumers participate in an aggregation program.[121]
- In 2006, the Public Utilities Commission of Ohio (PUCO) was concerned that the market had not developed sufficiently to quickly move to market based rates. PUCO adopted rate stabilization plans of three to five years duration for each utility, which went into effect in 2006.[122] The Ohio Supreme Court ruled that PUCO's adoption of such plans was contrary to state law, given that certain generation costs were being recouped through distribution rates.[123]
- In 2008, SB 221 became law, modifying SB 3. SB 221 required each electric distribution utility to file an updated electric security plan, reflecting a "cost-based" valuation of its generation investment and the costs of operating those facilities. The law allows a utility to file and implement a "market rate offer" with customers paying the lowest price produced by either the electric security plan or the market rate offer. [124] Essentially, the 2008 law allowed the PUC to economically regulate utility-owned generation, a function that was eliminated under SB 3.

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[118] Ohio 123th General Assembly, Senate Bill 3 (July 6, 1999) codified at Ohio Revised Code, Title 49, Chapter 4928 (October 5, 1999). Available at http://codes.ohio.gov/orc/4928

[119] *Id*; SNL Energy, Regulatory Research Associates, Commission Profiles, Ohio, Electric Regulatory Reform/Industry Restructuring (Updated May 29, 2013).

[120] Ohio Revised Code, Title 49, Chapter 4928, §4928.54 (October 5, 1999). Available at http://codes.ohio.gov/orc/4928

[121] Distributed Energy Financial Group, LLC, 2012 ABACCUS: An Assessment of Restructured Electricity Markets, at 81 (December 2012). Available at http://defgllc.com/publication/2012-abaccus-electricity-restructuring-scorecard/

[122] Distributed Energy Financial Group, LLC, 2012 ABACCUS: An Assessment of Restructured Electricity Markets, at 80 (December 2012). Available at http://defgllc.com/publication/2012-abaccus-electricity-restructuring-scorecard/

[123] SNL Energy, Regulatory Research Associates, Commission Profiles, Ohio, Electric Regulatory Reform/Industry Restructuring (Updated May 29, 2013).

[124] Ohio 127th General Assembly, Amended Substitute Senate Bill 221 (July 31, 2008). Available at http://www.legislature.state.oh.us/BillText127/127_SB_221_EN_N.pdf; SB 221 is codified at Ohio Revised Code, Title 49, Chapters 9, 4905, and 4928 (amended sections 4905.31, 4928.01, 4928.02, 4928.05, 4928.09, 4928.14, 4928.17, 4928.20, 4928.31, 4928.34, 4928.35, 4928.61, 4928.67, 4929.01, and 4929.02; enacted sections 9.835, 3318.112, 4928.141, 4928.142, 4928.143, 4928.144, 4928.145, 4928.146, 4928.151, 4928.24, 4928.621, 4928.64, 4928.65, 4928.66, 4928.68, 4928.69, and 4929.051) (July 31, 2008).

2012 Annual Average Retail Price

- Residential: 11.67 cents per kWh
- Commercial: 9.47 cents per kWh
- Industrial: 6.22 cents per kWh

Reliability/Capacity Issues

- The PJM Interconnection has a number of pending cases at FERC related to reliability and capacity issues:
  - PJM uses a minimum offer price rule (MOPR) to prevent suppliers from bidding to sell power at below competitive price levels. However, arguing that the PJM market does not incentivize the building of enough new generation to serve their states, New Jersey and Maryland officials began to develop initiatives to subsidize the construction of new generating capacity. After various FERC orders and subsequent changes to the MOPR, this issue is still ongoing.[125]
  - After financial traders discovered advantages of submitting "up-to" bids to hedge their exposure to congestions costs, PJM has asked FERC to approve tariff revisions governing such bids.[126]
  - FERC has an open docket to address capacity deliverability issues between MISO and PJM. In a presentation to FERC at its June Open Meeting, the Organization of PJM States and the Organization of MISO States provided joint comments that acknowledge the presence of potential barriers to participation in the MISO and PJM capacity markets, but believe the issue is whether such barriers are appropriate and/or reasonable.[127]

Treatment of Residential Customers

- As of June 2012, 42.19% of residential customers switched providers. The switching at the residential level is predominately through opt-out aggregation.[128]

Mandated Rate Reductions

- A 5% residential generation-related rate reduction occurred from 2001 to 2005.[129]

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[125] FERC Docket No. ER13-535

[126] FERC Docket No. ER13-1654

[127] FERC Docket No. AD12-16-000; Joint Comments of the Organization of PJM States, Inc. and the Organization of MISO States. http://www.ferc.gov/industries/electric/indus-act/rto/oms-opsi.pdf

[128] Distributed Energy Financial Group, LLC, 2012 ABACCUS: An Assessment of Restructured Electricity Markets, at 82 (December 2012). Available at http://defgllc.com/publication/2012-abaccus-electricity-restructuring-scorecard/

[129] Ohio 123th General Assembly, Senate Bill 3 (July 6, 1999) codified at Ohio Revised Code, Title 49, Chapter 4928 (October 5, 1999). Available at http://codes.ohio.gov/orc/4928; SNL Energy, Regulatory Research Associates, Commission Profiles, Ohio, Electric Regulatory Reform/Industry Restructuring (Updated May 29, 2013).

Current Actions at PUC/ISO/RTO/Legislature

- On December 12, 2012, PUCO initiated an investigation into its retail electric market. The workshops are ongoing, through December 2013, with a status report due to PUCO by Commission Staff on January 16, 2014. PUCO's investigation is focused on market design and corporate separation.[130]

Divestiture

- Utilities were not required to divest, but were required to unbundle rates into generation, transmission and distribution components.[131]

District of Columbia

History

- The Retail Electric Competition and Consumer Protection Act of 1999 provided authority for retail choice.[132]
- The District of Columbia Public Service Commission (DCPSC) issued Order Nos. 11576 (December 30, 1999) and 11796 (September 18, 2000) to allow all residential and commercial customers to choose an alternative electric supplier effective January 2001.[133]
- Potomac Electric Power Company (PEPCO) is the sole electric distribution company and is responsible for all emergencies.[134]
- The DCPSC has continually reexamined the standard offer service process, however, PEPCO remains the standard offer service provider in the District of Columbia, utilizing a competitive auction to procure electric supply.[135]

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[130] PUCO Case No. 12-3151-EL-COI. Commission Entry (May 29, 2013). Available at http://dis.puc.state.oh.us/CaseRecord.aspx?Caseno=12-3151&link=DIVA

[131] Ohio Revised Code, Title 49, Chapter 4928, §4928.17(E) and §4928.31 (October 5, 1999). Available at http://codes.ohio.gov/orc/4928

[132] The Retail Electric Competition and Consumer Protection Act of 1999 is available at http://www.dcpsc.org/pdf_files/customerchoice/electric/electric_retailchoiceleg.pdf; Codified at District of Columbia Official Code Title 34, Subtitle III, Chapter 15. Available at http://www.lexisnexis.com/hottopics/dccode/

[133] District of Columbia Public Service Commission, Formal Case No. 945 In the Matter of the Investigation into Electric Service Market Competition and Regulatory Practices, Order No. 11576 (December 30, 1999). Available at http://www.dcpsc.org/edocket/docketsheets_pdf_FS.asp?caseno=FC945&docketno=341&flag=C&show_result=Y; District of Columbia Public Service Commission, Formal Case No. 945, Phase II, In the Matter of the Investigation into Electric Service Market Competition and Regulatory Practices, Order No. 11796 (September 18, 2000, 1999). Available at http://www.dcpsc.org/edocket/docketsheets_pdf_FS.asp?caseno=FC945&docketno=483&flag=C&show_result=Y

[134] District of Columbia Public Service Commission, Retail Electric Restructuring in DC. Available at http://205.177.170.130/customerchoice/whatis/electric/elec_restruc.shtm; Distributed Energy Financial Group, LLC, 2012 ABACCUS: An Assessment of Restructured Electricity Markets, at 55. (December 2012). Available at http://defgllc.com/publication/2012-abaccus-electricity-restructuring-scorecard/

Annual Average Retail Price

- Residential: 12.29 cents per kWh
- Commercial: 12.03 cents per kWh
- Industrial: 5.44 cents per kWh

Reliability/Capacity Issues

- All alternative electric suppliers that operate in the District of Columbia are members of PJM. PJM and MISO, currently have a docket open with FERC as they struggle to resolve capacity deliverability issues at their seam, which ultimately affects reliability and costs for customers in PJM and MISO.[136]

Treatment of Residential Customers

- On June 1, 2013, the cost of generation for residential standard offer service customers increased from a summer rate of 8.4 cents per kWh to 8.8 cents per kWh and increased from a winter rate of 8.2 cents per kWh to 8.7 cents per kWh. As a result, the electricity generation portion of the average monthly residential bill has increased from $58.45 to $61.35.[137]
- As of May 2013, PEPCO retained 85.1% of residential electric market share, representing 83.8% of residential demand.[138]

Mandated Rate Reductions

- Residential and non-residential customer rate reductions of 7% and 6.5%, respectively, were phased in, with the final steps to be implemented following the sale of PEPCO's generation assets.[139] Rates were capped at the reduced levels throughout a transition period that extended to February 7, 2005, but as part of an agreement reached in conjunction with the DCPSC's 2002 approval of the merger of PEPCO and Conectiv, the distribution rate cap was extended to August 7, 2007 for non-Residential Aid Discount customers and to August 31, 2009 for Residential Aid

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[135] District of Columbia Public Service Commission, Retail Electric Restructuring in DC, Standard Offer Service (SOS) After Price Caps End on February 7, 2005. Available at http://205.177.170.130/customerchoice/whatis/electric/elec_restruc.shtm

[136] FERC Docket No. AD12-16-000; Presentations on this issue were presented to FERC at its June 20, 2013 Open Meeting and are available at http://www.ferc.gov/

[137] Press Release, District Utility Regulators Announce New Standard Offer Service Rates for Electric Customers, June 3, 2013. Available at http://www.dcpsc.org/pdf_files/pressreleases/PR_New_SOS_Rates_Elec_Cust.pdf

[138]Customer Choice of Electric Services in the District of Columbia – Presentation, at 36. Available at http://www.dcpsc.org/hottopics/electric.pdf

[139] District of Columbia Public Service Commission, Formal Case No. 945 In the Matter of the Investigation into Electric Service Market Competition and Regulatory Practices, Order No. 11576 (December 30, 1999). Available at http://www.dcpsc.org/edocket/docketsheets_pdf_FS.asp?caseno=FC945&docketno=341&flag=C&show_result=Y

Discount customers. The generation rate cap for Residential Aid Discount customers was also extended until February 8, 2007.[140]

Current Actions at PUC/ISO/RTO/Legislature

- After numerous complaints, in May 2013, the DCPSC launched an investigation to determine whether Starion Energy, an alternative electric supplier, is engaging in deceptive practices that hurt consumers.[141]
- The PJM Interconnection has a number of pending cases at FERC related to reliability and capacity issues:
  - PJM uses a minimum offer price rule (MOPR) to prevent suppliers from bidding to sell power at below competitive price levels. However, arguing that the PJM market does not incentivize the building of enough new generation to serve their states, New Jersey and Maryland officials began to develop initiatives to subsidize the construction of new generating capacity. After various FERC orders and subsequent changes to the MOPR, this issue is still ongoing.[142]
  - After financial traders discovered advantages of submitting "up-to" bids to hedge their exposure to congestions costs, PJM has asked FERC to approve tariff revisions governing such bids.[143]
  - FERC has an open docket to address capacity deliverability issues between MISO and PJM. In a presentation to FERC at its June Open Meeting, the Organization of PJM States and the Organization of MISO States provided joint comments that acknowledge the presence of potential barriers to participation in the MISO and PJM capacity markets, but believe the issue is whether such barriers are appropriate and/or reasonable.[144]

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[140] District of Columbia Public Service Commission, Retail Electric Restructuring in DC, Electric Rate Reductions and Rate Caps. Available at http://205.177.170.130/customerchoice/whatis/electric/elec_restruc.shtm

[141] District of Columbia Public Service Commission, In the matter of the Investigation into the business and solicitation practices of Starion Energy in the District of Columbia and addressing the Petition of the Office of the People's Counsel to open a wide-ranging investigation of all Alternative Energy Suppliers Licensed in the District of Columbia, Case No. FC 1105 (Opened May 30, 2013). Available at http://www.dcpsc.org/edocket/docketsheets.asp?cbofctype=all&CaseNumber=FC+1105&ItemNumber=&orderno=&PartyFiling=&FilingType=&yr_filing=&Keywords=&FromDate=&ToDate=&toggle_text=Full+Text&show_result=Y&hdn_orderNumber=&hdn_chk_whole_search=&hdn_AssesmentType= ; See also Cheryl W. Thompson, D.C. energy bills from alternative suppliers subject of hearing, Washington Post (July 11, 2013). Available at http://www.washingtonpost.com/local/dc-energy-bills-from-alternative-suppliers-subject-of-hearing/2013/07/11/5e53383c-d43f-11e2-b05f-3ea3f0e7bb5a_story.html

[142] FERC Docket No. ER13-535

[143] FERC Docket No. ER13-1654

[144] FERC Docket No. AD12-16-000; Joint Comments of the Organization of PJM States, Inc. and the Organization of MISO States. http://www.ferc.gov/industries/electric/indus-act/rto/oms-opsi.pdf

Divestiture

- At the end of 1999, the DCSPC approved PEPCO's request to divest itself of generating units.
- On December 19, 2000, PEPCO completed the closing on the sale of the bulk of its electric power plants and other generation assets to Mirant Corporation for $2.75 billion.
- PEPCO also transferred ownership of its two District of Columbia plants (Benning and Buzzard Point) to a new unregulated subsidiary, Potomac Power Resources, Inc., and these two plants are operated by Mirant. PEPCO also signed a four-year contract with Mirant Corporation to buy back the power its customers need at prices below PEPCO's current average cost of production.
- On January 8, 2001, PEPCO completed the sale of its 9.7% interest in the Conemaugh Generation Station to Allegheny Energy, Inc. and PPL Corporation for $156 million.[145]

Delaware

History

- Electric restructuring was mandated in March 1999 and was phased in by October 1, 2000 for Delmarva Power & Light Company ("Delmarva") and April 2001 for Delaware Electric Cooperative. Customers were phased in beginning with large customers, followed by medium-sized customers and then residential and commercial customers.[146]
- In 2006, legislation was enacted that amended the 1999 law, by including a number of provisions designed to stabilize electricity pricing and utilization for Delaware consumers for both the short and long term. Provisions included allowing the utilities to own and operate generation, a competitive RFP process for the construction of cost-effective merchant generation in the state and the deferral of rate increases for residential and small commercial customers of Delmarva beginning May 1, 2006.[147]

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[145] District of Columbia Public Service Commission, Retail Electric Restructuring in DC, Divestiture of PEPCO's Plants. Available at http://205.177.170.130/customerchoice/whatis/electric/elec_restruc.shtm; District of Columbia Public Service Commission, Formal Case No. 945 In the Matter of the Investigation into Electric Service Market Competition and Regulatory Practices, Order No. 11576 (December 30, 1999). Available at http://www.dcpsc.org/edocket/docketsheets_pdf_FS.asp?caseno=FC945&docketno=341&flag=C&show_result=Y

[146] House Bill No. 10, codified at Delaware Code, Title 26, Chapter 10 (March 31, 1999). Available at http://delcode.delaware.gov/title26/c010/index.shtml.

[147] House Bill No. 6, Electric Utility Retail Customer Supply Act of 2006, amending provisions of Delaware Code, Title 26, Chapter 10 (April 6, 2006). Available at http://delcode.delaware.gov/sessionlaws/ga143/chp242.shtml

- During the transition period, Delmarva was somewhat insulated from market price fluctuations since the company could file for a rate increase if power costs rose by a certain amount.
- A post-transition framework is now in place under which the power to meet standard-offer-service requirements is procured competitively.[148]

2012 Annual Average Retail Price

- Residential – 13.59 cents/kWh
- Commercial – 10.11 cents/kWh
- Industrial – 8.33 cents/kWh

Reliability/Capacity Issues

- None.

Treatment of Residential Customers

- As of August 2012, 4.5% of residential customers have switched providers.[149]
- In 2005, the PSC determined that Delmarva should continue to provide standard offer service following the conclusion of the transition period. Delmarva was to procure the power for the standard offer service through the competitive wholesale market using an RFP process.
- Standard offer service rates were expected to increase by 59% or more for residential and small commercial customers upon expiration of the rate freeze based on the results of the initial auctions. As a result, legislation was passed that allowed for the increase to be phased in over three years: a 15% increase effective June 1, 2006, an incremental 25% effective January 1, 2007, and, an incremental 19% increase effective June 1, 2007. Amounts not collected during the phase-in were deferred for recovery through a separate customer-specific charge that was in place from January 1, 2008 through June 1, 2009. Customers were given the opportunity to "opt-out" of the plan, and customers representing about 50% of residential and small commercial customer load exercised this option.[150]

Mandated Rate Reductions

- Delmarva's residential rates were reduced 7.5% at the time retail competition was initiated and rates were frozen from October 1, 1999 through September 30, 2003.

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[148] Delaware Public Service Commission, Standard Offer Service. Available at http://depsc.delaware.gov/sos.shtml

[149] Distributed Energy Financial Group, LLC, 2012 ABACCUS: An Assessment of Restructured Electricity Markets, at 54 (December 2012). Available at http://defgllc.com/publication/2012-abaccus-electricity-restructuring-scorecard/

[150] House Bill No. 6, Electric Utility Retail Customer Supply Act of 2006, amending provisions of Delaware Code, Title 26, Chapter 10 (April 6, 2006). Available at http://delcode.delaware.gov/sessionlaws/ga143/chp242.shtml

The rate cap was extended until May 1, 2006 following the merger of Delmarva with Potomac Electric Power Company in 2002.[151]

- Residential rates were frozen for Delaware Electric Cooperative customers from April 1, 2000 through March 31, 2005. Following the removal of the rate cap, rates increased 8%.[152]

Current Actions at PUC/ISO/RTO/Legislature

- In July 2012, the Public Service Commission issued an Order to allow rule changes to the certification of Electric Suppliers to make electric choice more competitive, including changes to provide additional protection for customers, requiring electric suppliers to include additional details regarding the rates, terms, and conditions of service in their offers, and to make the certification process for Electric Suppliers more uniform.[153] Stakeholder workshops were held in August, October and December 2012 and in January 2013. Staff will propose amendments to the Supplier Rules and may propose changes to the Standard Offer Service procurement process that may help foster retail competition such as shorter contract terms. The Commission will then consider whether to accept the proposed amendments and/or revisions and create new rules.[154]
- On March 22, 2013, Delmarva Power and Light Company filed an application with the Commission seeking an increase in its electric base rates of 7.38%.[155]

Divestiture

- Delmarva divested the majority of its generation assets and was authorized to recover $16 million of stranded costs through a non-residential wires charge that expired in September 2002.[156]

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[151] Delaware Public Service Commission, Docket No. 01-0194, In the Matter of the Application of Delmarva Power & Light Company, Conectiv Communications, Inc., Potomac Electric Power Company, and New RC, Inc., for Permission to Transfer Control of Delmarva Power & Light Company and Conectiv Communications, Inc. Under the Provisions of 26 Del. C. §§215 and 1016, Order No. 5941 (April 16, 2002). Available at http://depsc.delaware.gov/orders/5941.pdf

[152] Distributed Energy Financial Group, LLC, 2012 ABACCUS: An Assessment of Restructured Electricity Markets, at 53 (December 2012). Available at http://defgllc.com/publication/2012-abaccus-electricity-restructuring-scorecard/

[153] Delaware Public Service Commission, PSC Regulation Docket No. 49, In the Matter of the Adoption of Rules and Regulations to Implement the Provisions of 26 Del. C. Ch. 10 Relating to the Creation of a Competitive Market for Retail Electric Supply Service. Order No. 8187 (July 17, 2012) Available at http://depsc.delaware.gov/orders/8187.pdf

[154] Delaware Public Service Commission, PSC Regulation Docket No. 49, In the Matter of the Adoption of Rules and Regulations to Implement the Provisions of 26 Del. C. Ch. 10 Relating to the Creation of a Competitive Market for Retail Electric Supply Service. Available at http://depsc.delaware.gov/electric.shtml#cases

[155] Delaware Public Service Commission, Docket No. 13-115. Available at http://depsc.delaware.gov/electric.shtml#cases

[156] SNL Energy, Regulatory Research Associates, Commission Profiles, Delaware, Electric Regulatory Reform/Industry Restructuring (Updated September 26, 2012).

Rhode Island

History

- Full retail access commenced in 1998 in accordance with 1996 legislation. As required by the law, each electric distribution company entered into contracts with wholesale suppliers for power to serve standard offer service (SOS). The wholesale supply contracts provided for increases in the per-kWh-rate of wholesale power supplied to the distribution companies in the event fuel prices increased above certain levels.[157]
- Legislation enacted in 2006 extended the availability of SOS through 2020.[158] Since 2010, SOS prices for large volume customers have been reset every three months. The prices for small volume customers are reset every six months. To the extent that the total cost of the utility's wholesale supply, including fuel charges, exceeds retail SOS revenues, the shortfall is recoverable from customers through a semi-annual standard-offer-adjustment provision.[159]

2012 Annual Average Retail Price

- Residential: 14.41 cents per kWh
- Commercial: 12.06 cents per kWh
- Industrial: 10.86 cents per kWh

Reliability/Capacity Issues

- With the advent of retail competition in the 1990s, the PUC's integrated resource planning framework was rescinded. However, legislation enacted in 2006 requires, among other things: (1) the establishment of a least-cost power procurement framework for electric standard offer service (SOS); (2) implementation of programs to encourage electric fuel diversity, distributed generation, and demand reduction; and, (3) the development of renewable energy resources.
- PUC least-cost procurement standards require electric distribution companies to submit triennially, beginning Sept. 1, 2008 through Sept. 1, 2017, plans for system reliability and energy efficiency and conservation procurement.

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[157] Rhode Island General Assembly, An Act Relating to the Utility Restructuring Act of 1996, 96-H 8124B (August 7, 1996) Available at http://liheap.ncat.org/pubs/ribill.htm; Rhode Island General Laws Title 39, Chapter 39-1, Section 39-1-27.3 (1996). Available at http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-1/39-1-27.3.HTM

[158] Rhode Island General Assembly , An Act Relating to Public Utilities and Carriers, S 2905, (introduced March 8, 2006). Available at http://webserver.rilin.state.ri.us/BillText06/SenateText06/S2905Aaa.pdf ; Rhode Island General Laws Title 39, Chapter 39-1, Section 39-1-27.3(b) (2006). Available at http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-1/39-1-27.3.HTM

[159] SNL Energy, Regulatory Research Associates, Commission Profiles, Rhode Island, Electric Regulatory Reform/Industry Restructuring (Updated September 20, 2012).

Treatment of Residential Customers

- A non-bypassable transition charge for the recovery of stranded costs is to be collected from all distribution customers through Dec. 31, 2009.[160]
- As of June 2012, 3.2% of residential customers switched providers.[161]

Mandated Rate Reductions

- From 2004 - 2009, Narragansett Electric operated under a rate plan, whereby electric distribution rates were largely frozen, but were subject to adjustments for certain factors. A service quality plan was in effect during the rate-freeze, with potential financial penalties of as much as $2.2 million annually.[162]

Current Actions at PUC/ISO/RTO/Legislature

- In February 2012, National Grid filed the proposed Standard Offer Service (SOS) and RES Procurement plans for 2013. National Grid proposed to continue to procure SOS through a combination of full requirements service contracts and spot purchases, with the mix of long-term and spot to depend on the customer group. The RI PUC issued an order in August 2012, stating that there is "no evidence in the record that the electricity supply market has changed in a way that would necessitate a change."[163]
- Granting a request by Dominion Energy Marketing Inc., on June 14, 2013, the Federal Energy Regulatory Commission directed ISO New England Inc. to implement tariff changes before the upcoming winter allowing a generator called on to provide a critical reliability service to recover the fuel costs associated with providing that service. The commission also said Dominion could recoup $336,095 in extra fuel costs it incurred last winter while providing critical reliability service.[164]

Divestiture

- While the 1998 law required the investor-owned utilities to spinoff or sell 15% of their generating assets in order to estimate market value, New England Electric System and Eastern Utilities Associates divested 100% of their generating assets as

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160 State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers, Summary of Major Provisions of the Rhode Island Utility Restructuring Act of 1996 (H-8124 Substitute B3), Transition Charges. Available at http://www.ripuc.org/utilityinfo/electric/ura1996summ.html

161 Distributed Energy Financial Group, LLC, 2012 ABACCUS: An Assessment of Restructured Electricity Markets, at 89 (December 2012) Available at http://defgllc.com/publication/2012-abaccus-electricity-restructuring-scorecard/

162 SNL Energy, Regulatory Research Associates, Commission Profiles, Rhode Island, Alternate Regulation (Updated September 20, 2012).

163 State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers, Docket No. 4315, National Grid's 2013 Standard Offer Service (SOS) Procurement Plan and 2013 Renewable Energy Supply Procurement Plan , Order No. 20795 at 6 (August 10, 2012). Available at http://www.ripuc.org/eventsactions/docket/4315-NGrid-Ord20795(8-10-12).pdf

164 Glen Boshart, SNL Energy, *FERC: ISO-NE needs to change tariff to allow must-run generators to recover fuel costs* (June 14, 2013). FERC Docket Nos. ER13-1291-000 and EL13-72-000, Order Granting Cost Recovery, Instituting Section 206 Proceeding, and Establishing Refund Effective Date (June 14, 2013).

part of their restructuring plans. The two entities have since merged and are both part of National Grid-USA, whose operating utility is Narragansett Electric.[165]

California

History

- In 1992, the California Public Utilities Commission (CPUC) began to develop a restructuring plan, which ultimately became the basis of California Assembly Bill AB1890, passed in September 1996.[166]
- The California Independent System Operator (CAISO) and the Power Exchange became operational in 1998, and at that time, all customers became eligible for direct access.[167]
- In January 2001, PG&E filed for bankruptcy protection. Subsequently, Governor Davis directed the Department of Water Resources to use $12 billion to buy power for the utilities and negotiate long-term contracts with suppliers.[168]
- In March 2001, FERC ordered suppliers to make refunds to utilities.[169] In June 2001, FERC voted to impose price controls on wholesale electricity prices for California and ten other Western states. [170]
- On September 20, 2001, the CPUC suspended direct access pursuant to AB1X.[171]
- CPUC Decision D.10-03-022 implements Senate Bill 695 which provided for a limited reopening of direct access to non-residential customers starting in April 2010. The intent of the reopening is to allow direct access to return to the maximum level experienced prior to the suspension.[172]

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[165] SNL Energy, Regulatory Research Associates, Commission Profiles, Rhode Island, Electric Regulatory Reform/Industry Restructuring (Updated September 20, 2012).
[166] California Assembly Bill No. 1890 (September 24, 1996). Available at http://large.stanford.edu/publications/coal/references/docs/ab_1890_bill_960924_chaptered.pdf
[167] SNL Energy, Regulatory Research Associates, Commission Profiles, California, Electric Regulatory Reform/Industry Restructuring (Updated June 19, 2013).
[168] Authorized by emergency legislation AB 1X, February 1, 2001, this state procurement lasted until 2003.
[169] FERC Docket No. EL00-95-000, et al., Order Directing Sellers to Provide Refunds of Excess Amounts Charged for Certain Electric Energy Sales During January 2001 or, Alternately, to Provide Further Cost or Other Justification for
Such Charges (March 9, 2001). Available at http://www.ferc.gov/industries/electric/indus-act/wec/chron/03-09-01-order.pdf
[170]FERC Docket No. EL00-95-031, et al., Order on Rehearing of Monitoring and Mitigation Plan for the California Wholesale Electric Markets, Establishing West-Wide Mitigation, and Establishing Settlement Conference (June 19, 2001). Available at http://www.wapa.gov/sn/marketing/docs/fercmarket.PDF
[171] California Public Utilities Commission, Interim Opinion Suspending Direct Access, Decision D. 01-09-060 (September 20, 2001). Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/9812.PDF
[172] California Public Utilities Commission, Regarding Increased Limits for Direct Access Transactions, Decision 10-03-022 (March 15, 2010). Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/114976.PDF; *See also* California Public Utilities Commission, Senate Bill 695 Will Allow New Non-Residential Customers to Take Direct Access

- In March 2010, the CPUC increased the amount of load that may be served by competitive energy suppliers in each investor-owned utility's service territory and established a four-year phase-in schedule for the increased load. The maximum allowed load cap will be realized in 2013.[173]

2012 Annual Average Retail Price

- Residential: 15.50 cents per kWh
- Commercial: 13.51 cents per kWh
- Industrial: 10.68 cents per kWh

Reliability/Capacity Issues

- The CPUC is planning to install a flexible capacity procurement mandate on its regulated utilities as a way to improve the state's resource adequacy program. In a proposed decision issued May 28, 2013 the CPUC laid out an interim framework covering the years 2015-2017 as an additional component of local capacity resource adequacy requirements on utilities and other load-serving entities. The forward capacity market is being proposed as a way to avoid the pitfalls of too much intermittent renewable energy and too little flexible supply.[174]

Treatment of Residential Customers

- In reopening direct access in 2009, the Legislature only allowed non-residential customers to participate. However, residential customers that had remained with a competitive electric service provider prior to direct access being suspended in 2001 are still eligible to switch providers or to return to their incumbent utility. Approximately 0.1% of residential customers participate in direct access.[175]

Service from an Electric Service Provider. Available at http://www.cpuc.ca.gov/PUC/energy/Retail+Electric+Markets+and+Finance/Electric+Markets/Direct+Access/091204_sb695.htm; California State Assembly, Ratepayer Protection Act, SB 695 (October 11, 2009). Available at http://www.leginfo.ca.gov/pub/09-10/bill/sen/sb_0651-0700/sb_695_bill_20091011_chaptered.html

[173] California Public Utilities Commission, Regarding Increased Limits for Direct Access Transactions, Decision 10-03-022 (March 15, 2010). Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/114976.PDF

[174] California Public Utilities Commission, Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local Procurement Obligations, Decision Adopting Local Procurement Obligations for 2014, a Flexible Capacity Framework, and Further Refining the Resource Adequacy Program, Rulemaking 11-10-023 (May 28, 2013). Available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M065/K705/65705989.PDF; Christine Cordner, SNL Energy, *Calif. summit participants debate merits, pitfalls of forward capacity market* (February 27, 2013).

[175] California State Assembly, Ratepayer Protection Act, SB 695 (October 11, 2009). Available at http://www.leginfo.ca.gov/pub/09-10/bill/sen/sb_0651-0700/sb_695_bill_20091011_chaptered.html; California Public Utilities Commission, Direct Access Service Requests. Available at http://www.cpuc.ca.gov/PUC/energy/Retail+Electric+Markets+and+Finance/Electric+Markets/Direct+Access/thru2008.htm

Mandated Rate Reductions

- A 10% reduction in rates (from January 1998 levels) was mandated for residential and small commercial customers if they remained with their current utility, beginning January 1, 1998.[176]
- This reduction remained in place until utilities recovered their generation related uneconomic costs (stranded costs) through the Competitive Transition Charge, or until March 31, 2002, whichever was earlier.[177]

Current Actions at PUC/ISO/RTO/Legislature

- Judge Philip Baten in February 2013 recommended that FERC order seven power suppliers to refund close to $91 million to those entities that made purchases in the CAISO and PX markets during the refund period. Baten specifically determined that Bonneville Power Administration should pay $44.5 million, the Western Area Power Administration should pay $621,377, BC Hydro and Power Authority subsidiary Powerex Corp. should pay $300,376 and Avista Corp. subsidiary Avista Energy Inc. should pay $179,211 in refunds for faulty energy exchange sales. In addition, he said Powerex, Bonneville and Constellation New Energy Inc. should pay $27.3 million, $15 million and $2.9 million, respectively, in refunds for forward transactions (those having durations of more than 24 hours).[178]
- Separately, the U.S. Court of Federal Claims in Washington, D.C., on April 2, 2013 determined that Bonneville Power Administration and the Western Area Power Administration will be subject to damage claims, totally close to $2 billion, related to sales made during and shortly after summer 2001. In March 2012, the same court held BPA and WAPA responsible for refunds related to other sales made during the crisis period. The court determined that BPA and WAPA are contractually bound to keep no more than the just and reasonable prices FERC sets for the power sales they made during the energy crisis.[179]
- In an April 10, 2013 opinion, the U.S. Court of Appeals for the 9th Circuit reversed a decision of the U.S. District Court for the District of Nevada, allowing natural gas buyers to pursue antitrust lawsuits against Williams Cos. Inc., ONEOK Inc., El Paso Corp., Duke Energy Trading & Marketing LLC, American Electric Power Co. Inc., Xcel Energy Inc. and many other companies involved in gas trading over allegations of

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[176] California Assembly Bill No. 1890, codified as California Public Utilities Code, Division 1, Part 1, Chapter 2.3, Section 368(a). (September 24, 1996). Available at http://www.leginfo.ca.gov/cgi-bin/calawquery?codesection=puc

[177] California Assembly Bill No. 1890 (September 24, 1996). Available at http://large.stanford.edu/publications/coal/references/docs/ab_1890_bill_960924_chaptered.pdf

[178] FERC Docket No. EL00-95-248l, Initial Decision (February 15, 2013). Available at http://www.eenews.net/assets/2013/02/20/document_gw_01.pdf

[179] U.S. Court of Federal Claims, Case No. 07-184C (April 2, 2012). Available at http://docs.justia.com/cases/federal/district-courts/federal-claims/cofce/1:2007cv00184/22103/256/0.pdf?ts=1364997045

price manipulation during the Western energy crisis from 2000 to 2002. The appeals court reinstated the lawsuits and sent the case back to the District Court for further proceedings consistent with its opinion.[180]

Divestiture

- Utilities were required to divest at least 50% of their fossil generating assets. Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric sold virtually all of their in-state fossil generating capacity at prices significantly above book value.[181]

New Hampshire

History

- One of the early adopters of electric restructuring, New Hampshire enacted legislation in May 1996 and retail choice was to become available by January 1, 1998.[182]
- Granite State Electric Company was the first to open its retail load to competition in August 1998 but litigation delayed Public Service Company of New Hampshire (PSNH), who serves approximately 70 percent of the retail customers in New Hampshire, from allowing retail competition until May 2001. The Unitel Energy Systems (UES) companies introduced retail choice as of May 1, 2003, following a merger of three companies in late 2002.[183]
- The initial legislation mandated full divestiture of generation.[184] Full divestiture was scaled back in response to the 2000-2001 California energy crisis.
- Since retail competition began for PSNH, the legislature has amended the Electric Industry Restructuring Act numerous times over the years to address new issues, such as extending transition service and modifying pricing levels for such service as well as default service, and repealing mandatory divestiture.[185]

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[180] U.S. Court of Appeals for the 9th Circuit Nos. 11-16786, 11-16798 (April 10, 2013). Available at http://cdn.ca9.uscourts.gov/datastore/opinions/2013/04/10/11-16786.pdf

[181] SNL Energy, Regulatory Research Associates, Commission Profiles, California, Electric Regulatory Reform/Industry Restructuring (Updated June 19, 2013).

[182] New Hampshire Statutes, Chapter 374-F (May 21, 1996). Available at http://www.gencourt.state.nh.us/rsa/html/NHTOC/NHTOC-XXXIV-374-F.htm.

[183] New Hampshire Public Utilities Commission, Electric. Available at http://www.puc.state.nh.us/Electric/electric.htm

[184] Distributed Energy Financial Group, LLC, 2012 ABACCUS: An Assessment of Restructured Electricity Markets, at 72(December 2012). Available at http://defgllc.com/publication/2012-abaccus-electricity-restructuring-scorecard/

[185] See, for example, New Hampshire Statutes, Chapter 374-F, Section 374-F:4, revised in 1997, 1998, 1999, 2000, 2001, 2002, 2004, 2007, and 2009. Available at http://www.gencourt.state.nh.us/rsa/html/XXXIV/374-F/374-F-4.htm

- Although competitive suppliers are welcome to provide service in restructured franchise areas, most residential customers receive Default Energy Service.[186]

2012 Annual Average Retail Price

- Residential - 16.12 cents/kWh
- Commercial - 13.41 cents/kWh
- Industrial - 11.82 cents/kWh

Reliability/Capacity Issues

- None. PSNH continues to own most of its generation assets.

Treatment of Residential Customers

- There is about 5% residential switching for PSNH customers as of October 2012.[187]
- PSNH continues to provide default energy service to customers who do not select a competitive supplier. The output of its owned generation assets is used to meet default service requirements and is regulated by the New Hampshire Public Utility Commission (PUC).[188]
- Distribution-only companies, Granite State Electric, and Unitil Energy Systems, supply default energy service through a request-for-proposals process supervised by the PUC.
- In September 2012, the PUC authorized Granite State Electric Company to increase default service rates for medium and large C&I customers and for 100% of requirements for residential and small commercial customers. Beginning November 1, 2012, the bill impact for large customers will be 19-24% and for residential customers (500 kWh) would see an increase from $60.54 to $68.75, or 13.6%.[189]

Mandated Rate Reductions

- PSNH customers received an automatic 5% rate reduction on October 1, 2000 and another reduction totaling a combined average of 15% - 17% for residential customers when PSNH began retail competition on May 1, 2001.[190]

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[186] New Hampshire Public Utilities Commission, Electric. Available at http://www.puc.state.nh.us/Electric/electric.htm

[187] Dave Solomon, *Thousands drop PSNH for cheaper electricity supplier*, New Hampshire Union Leader (October 27, 2012). Available at http://www.unionleader.com/article/20121028/NEWS02/710289914

[188] SNL Energy, Regulatory Research Associates, Commission Profiles, New Hampshire, Electric Regulatory Reform/Industry Restructuring (Updated June 19, 2013).

[189] New Hampshire Public Utilities Commission, Petition for Approval of Default Service Solicitation and Resulting Rates for the Large and Small Customer Groups for the Period Beginning November 1, 2012, Order Approving Solicitation and Selection of Default Service Supply and Resulting Rates, Order No. 25,416, Docket DE 12-023. (September 21, 2012) Available at http://www.puc.state.nh.us/Regulatory/Orders/2012orders/25416e.pdf.

[190] News Release, NH Supreme Court Upholds PSNH Deregulation Plan. Available at http://nuwnotes1.nu.com/apps/mediarelease/psnhpr.nsf/0/00C9F78523A30C7E85256BA500665F0E?OpenDocument

- Granite State Electric Company customers received a 10% rate reduction beginning on July 1, 1998 and a further 7% reduction on September 1, 1998.[191]

Current Actions at PUC/ISO/RTO/Legislature

- On January 18, 2013, the PUC opened an investigation into the Market Conditions, Default Service Rate, Generation Ownership and Impacts on the Competitive Electricity Market as it relates to PSNH.[192] A Staff Report was issued on June 7, 2013, suggesting that PSNH should rid itself of its coal-fired power plants in order to lower the cost of electricity for default service. [193] PSNH recently filed its response to the Staff Report, taking issue with Staff's conclusions and suggesting "the PUC report glosses over 10 years of legislative mandates that resulted in PSNH retaining coal-fired plants in Bow and Newington; "trivializes" the region's overreliance on natural gas and the safety net the plants provide."[194]
- In February 2013, Resident Power, a competitive energy provider in New Hampshire, was forced to switch power suppliers for the majority of its customers as a result of the ISO-NE suspending Power New England, apparently due to financial reasons. The newspaper article reports that "the problem was apparently triggered by the sharp rise in the cost of electricity produced by natural gas, which roughly doubled in January and doubled again in February. This has cut into the margins that have allowed competitive companies to underprice utilities like PSNH."[195]
- The PUC reports on its website that a major change in the wholesale New England electric markets is occurring due to a massive increase in transmission spending. Total transmission costs in the region are expected to grow from a little over $1 billion in 2007 to a cumulative total of more than $8.5 billion by 2012. This large increase in spending is due to lack of capital investment spending in the last 10 to 15 years and increased financial incentives awarded by FERC to companies building new transmission projects. The New Hampshire PUC, along with other New England state commissions, is presently working with ISO-NE and the transmission companies to develop better cost estimating and cost containment methods for

[191] Citizens for Tax Justice, Status of State Electric Utility Deregulation Activity as of April 1, 1999, compile by the Energy Information Administration. (April 1, 1999) Available at http://www.ctj.org/html/util.html
[192] New Hampshire Public Utilities Commission, Docket IR 13-020 (January 18, 2013).
[193] Staff of the New Hampshire Public Utilities Commission and The Liberty Consulting Group, Public Service Company of New Hampshire, Report on *Investigation into Market Conditions*, Default Service Rate, Generation Ownership and Impacts on the Competitive Electricity Market (June 7, 2013). Available at http://www.puc.nh.gov/Electric/IR%2013-020%20PSNH%20Report%20-%20Final.pdf.
[194] New Hampshire Union Leader, *PSNH fires back on coal-fired plants.* (July 5, 2013). Available at http://pro.energycentral.com/professional/news/power/news_article.cfm?id=29215212
[195] David Brooks, "Resident Power can still operate as electricity seller in NH," The Telegraph. (February 21, 2013) Available at http://www.nashuatelegraph.com/business/994382-464/resident-power-can-still-operate-as-electricity.html.

these new projects to ensure just and reasonable electricity prices for New England's ratepayers.[196]

- In late 2010, ISO New England launched a major Strategic Planning Initiative to address concerns about resource performance and New England's increased reliance on natural gas for electric generation. An outcome of such reliance on natural gas is that gas pipeline transportation constraints are common and the region must rely on aging oil- and coal-fired generators to maintain reliability during peak demand periods or when the gas pipeline system is limited. Since the fall of 2012, the ISO and stakeholders have been developing short- and long-term solutions to mitigate the risks related to generator resource performance.[197]

Divestiture

- PSNH sold its share of the Seabrook Nuclear Power Facility in December 2002 in compliance with enacted legislation and the PSNH Restructuring Settlement Agreement.[198] PSNH still owns fossil and hydropower facilities and is prohibited from selling its generation assets without prior PUC approval.[199]
- Granite State Electric, and Unitil Energy Systems sold all their generation assets as part of their restructuring agreements.[200]
- The PUC authorized PSNH to issue up to $670 million of bonds to securitize a portion of the company's stranded costs. In 2001, PSNH issued $525 million of such bonds with a 2013 maturity date, and in 2002 issued an additional $50 million of bonds that matured in 2008.[201]

Michigan

History

- In 2000, Michigan implemented restructuring through the "Consumer Choice and Electricity Reliability Act." The Act effectively "unbundled" generation, transmission and distribution, divestiture of utility transmission function, and allowed other power generators inside and outside Michigan to consign their electricity to the

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[196] New Hampshire Public Utilities Commission, Electric, Wholesale and Regional Issues. Available at http://www.puc.nh.gov/Electric/wholesaleandregionalissues.htm.
[197] ISO New England, 2013 Regional Electricity Outlook. Available at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/2013_reo.pdf.
[198] New Hampshire Public Utilities Commission, Docket DE 99-099, Final Order. (April 19, 2000). Available at http://www.puc.state.nh.us/Regulatory/Orders/2000ords/23443E.PDF.
[199] Senate Bill 472 enacted April 2003, http://www.gencourt.state.nh.us/rsa/html/XXXIV/369-B/369-B-3-a.htm.
[200] SNL Energy, Regulatory Research Associates, Commission Profiles, New Hampshire, Electric Regulatory Reform/Industry Restructuring (Updated June 19, 2013).
[201] SNL Energy, Regulatory Research Associates, Commission Profiles, New Hampshire, Electric Regulatory Reform/Industry Restructuring (Updated June 19, 2013).

transmission grid and thus compete for sales to industrial, commercial and residential customers.[202]

- Legislation enacted in 2008 modified the electric choice framework to limit the amount of power in a utility's distribution service territory provided by alternative suppliers at any given time to 10% of the utility's weather-adjusted retail sales for the preceding calendar year.[203]

2012 Annual Average Retail Price

- Residential: 14.12 cents per kWh
- Commercial: 10.93 cents per kWh
- Industrial: 7.73 cents per kWh

Reliability/Capacity Issues

- None

Treatment of Residential Customers

- The number of residential customers participating in electric choice programs is negligible.

Mandated Rate Reductions

- The Consumer Choice and Electricity Reliability Act imposed a 5% rate cut and freeze on residential and small commercial rates until Dec. 31, 2003. Residential customer rates were to be capped through at least Jan. 1, 2006, with no increases permitted until the earlier of Dec. 31, 2013, or until the PSC determined that the utility meets a market power test and has completed certain transmission expansion requirements. Consumers Energy and Detroit Edison satisfied both conditions in 2002. Commercial customer rates were capped through year-end 2004.[204]

Current Actions at PUC/ISO/RTO/Legislature

- According to the Michigan Public Service Commission Annual Report on the Status of Electric Competition in Michigan, 2012 was the first year that Indiana Michigan

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[202] State of Michigan, 90th Legislature, Regular Session of 2000, SB 937 (June 5, 2000). Available at http://www.legislature.mi.gov/documents/1999-2000/publicact/pdf/2000-PA-0141.pdf;Theodore Bolema, Mackinac Center for Public Policy, Central Michigan University, *Electricity Restructuring in Michigan*, available at http://www.ftc.gov/bcp/workshops/energymarkets/presentations/bolema.pdf

[203] State of Michigan, 94th Legislature, Regular Session of 2008, HB 5524, Public Act 286 (October 6, 2008). Available at http://www.legislature.mi.gov/documents/2007-2008/publicact/pdf/2008-PA-0286.pdf; On September 29, 2009, in case U-15801 the Michigan Public Service Commission (MPSC) approved procedures dealing with the administration and allocation of electric load allowed to be served by alternative electric suppliers (AESs), under Public Act 286 of 2008. The procedures in their entirety are available at http://www.dleg.state.mi.us/mpsc/orders/electric/2009/u-15801etal_09-29-2009.pdf; Distributed Energy Financial Group, LLC, 2012 ABACCUS: An Assessment of Restructured Electricity Markets, at 69 (December 2012). Available at http://defgllc.com/publication/2012-abaccus-electricity-restructuring-scorecard/

[204] SNL Energy, Regulatory Research Associates, Commission Profiles, Michigan, Electric Regulatory Reform/Industry Restructuring.

Power Company and Upper Peninsula Power Company's customers could participate in electric choice programs.[205]

- On March 21 and 22, 2012, lawmakers in Michigan introduced legislation that would gradually raise the amount of demand that could be served by Alternative Energy Suppliers in each utility's service territory from 10% to 28% over a three-year period, plus up to 3% more per year thereafter, subject to conditions, restrictions and procedures specified in the bill. These bills were referred to the House and Senate Energy and Technology Committees with no subsequent action as of November 2012.[206] House Republicans are likely revisiting this issue in the 2013-2014 legislative session.

Divestiture

- Utilities that had commercial control over more than 30% of the generating capacity available to serve a relevant market were required to divest a portion of their generating capacity, sell generating capacity under a contract with a nonretail purchaser for at least 5 years, and/or transfer generating capacity to an independent brokering trustee for at least 5 years.[207]

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[205] The 2012 Annual Report is available at http://www.michigan.gov/documents/mpsc/status_of_electric_competition_2012_410152_7.pdf

[206] Bill summaries available at http://www.michiganvotes.org/2012-SB-1035; http://www.michiganvotes.org/2012-HB-5503

[207] State of Michigan, 90th Legislature, Regular Session of 2000, SB 937 (June 5, 2000). Available at http://www.legislature.mi.gov/documents/1999-2000/publicact/pdf/2000-PA-0141.pdf

EXHIBIT 1

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING ELECTRIC RESTRUCTURING ISSUES	DOCKET NO. E-00000A-02-0051 E-00000A-01-0630 **SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT'S AND NEW WEST ENERGY'S NOTICE OF FILING THEIR COMMENTS REGARDING ELECTRIC RESTRUCTURING ISSUES**

At the direction of the Commission at the workshop held on November 14, 2008, Salt River Project Agricultural Improvement and Power District and New West Energy Corporation submit their joint comments regarding the electric industry restructuring issues.

SUMMARY OF COMMENTS

The Commission has requested that interested parties address six points in their comments in this docket:

- potential risks and benefits of retail electric competition,
- whether retail electric competition is in the public interest,
- provider of last resort,
- whether the Commission's current electric competition rules are adequate,
- costs of competition, and
- other issues related to retail electric competition.

SRP and New West Energy address these issues comprehensively in the attached position paper. In summary:

1. Potential Risks and Benefits of Retail Electric Competition.

SRP and New West Energy begin, in Sections I and II, with a discussion of the economic theory behind electric industry restructuring. SRP and New West Energy point out that the economists believed that benefits would flow from reorganizing the industry to subject the generation sector to market forces. SRP and New West Energy conclude that, for Arizona, the obstacles and risks to restructuring the industry far outweigh the potential benefits. SRP and New West Energy point out that the growing emphasis on renewable energy resources and the reduction of carbon emissions add new costs, complexities and risks not anticipated when Arizona's Retail Electric Competition Rules were originally adopted. SRP and New West Energy emphasize that with our current fragile economy, and the emphasis on renewable resource and carbon reduction, it is not the time to experiment with new regulatory structures.

2. Whether or Not Competition is in the Public Interest.

Arizona now enjoys award winning electric service at prices that are among the lowest in the Southwest. Arizona utilities currently offer an array of options to customers, with more rolling out on a regular basis. In Section IV, SRP and New West Energy detail the customer satisfaction in Arizona, demonstrated by the receipt of national awards. SRP and New West Energy also detail some of the programs offered by SRP to its customers. Finally SRP and New West Energy compare Arizona retail prices to other states. The strong conclusion is that there is little need in Arizona to even consider assuming the risks of attempting to restructure the industry.

3. Provider of Last Resort (PLOR).

History has demonstrated that in each experiment with restructuring, the central issue is the failure to recognize and address the provider of last resort function of the electric system. It is the provider of last resort who assures that adequate system capacity is available to serve all of its retail load, assures that sufficient capacity for the system is built and maintained, insures long term planning, builds the generation mix needed for long term stability, provides a baseline price (sometimes called standard offer service) to mitigate retail price spikes, and assures that long term programs for renewable resources and carbon emission reductions are in place. It is crucial to carefully address the need for POLR responsibility in any restructured system. In Section II(C), SRP and New West Energy discuss the POLR issue, relying heavily on the testimony of Dr. Frank Graves, of the Brattle Group, whose testimony was filed in the Sempra docket. SRP and New West Energy conclude that the POLR has not been adequately addressed in Arizona, or elsewhere.

4. Whether the Commission's Current Electric Competition Rules are Adequate.

The conclusion naturally follows from the above discussions that the Commission rules in no sense contemplated the full extent of the accommodation for the POLR obligation. This issue cannot be ignored. Moreover, the Commission will need to significantly revise the rules as they are basically in disarray. Some have been waived, as the Commission determined that divestiture was not a good idea. Some have been invalidated by the Courts. And, even with restructured rules, there still exists a legal risk that they are contrary to Arizona law.

5. Costs of Competition.

There are two ways of looking at the issue. First, one can look at the hard costs to restructure the industry. These are huge. Estimates are that in the last go-around the Arizona utilities spent close to $100 million. The estimate in California is closer to $1 billion. But, the bigger issue is the cost of "competition as a whole". Conservatively, the experiment in California cost the State $10 billion. In the case studies presented in Section III, SRP and New West Energy show how customers, both residential and commercial, have consistently paid more and reaped few benefits in restructuring efforts across the nation. SRP and New West Energy urge the Commission to consider the total cost of an experiment, not just the cost of implementing a new system.

6. *Other Issues Relating to Retail Competition.*

SRP and New West Energy anticipate that the proponents of deregulation will argue that restructuring the entire industry is not necessary; just let a few large customers choose alternative providers. As discussed in the Conclusion section, a partial deregulation proposal simply shifts costs to other customers, particularly relating to the cost of providing POLR service. Partial deregulation would be a serious mistake, without any rational basis.

DATED this 30th day of January, 2009.

JENNINGS, STROUSS & SALMON, P.L.C.

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ORIGINAL and 13 copies filed this 30th day of January, 2009, with:

Docket Control
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COPY emailed this 30th day of January, 2009, to:

All parties of record

By: /s/ Michele Maser

Comments Regarding Electric Restructuring Issues of Salt River Project and New West Energy

January 30, 2009

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I. INTEREST AND POSITION OF SALT RIVER PROJECT AND NEW WEST ENERGY

This position paper is presented jointly by Salt River Project and New West Energy. Salt River Project has a significant interest in the issues pending in this docket. First, SRP and the Commission have a statutory obligation to coordinate their efforts relating to electric industry restructuring (A.R.S. §§ 30-802(A)[1], 30-806(A)[2], and 30-807(A)[3]). Second, SRP has a strong practical interest as its planning and economics will be directly effected were deregulation to be reinstituted in Arizona. New West Energy, an electric service provider who held certificates in Arizona and California, and which is owned by SRP, has an interest to insure that Arizona does not repeat the mistakes of others.

SRP and New West Energy have spent significant effort in analyzing the experiences in other states and countries of their experiments into electric industry restructuring. Their conclusion is that industry restructuring, or "deregulation" or "retail competition", has consistently failed to deliver benefits to consumers. Failed restructuring approaches have generally led to much wasted money and higher costs.

This is not the result that SRP and New West Energy want for Arizona. The economy is teetering and customers can ill afford unnecessary increases in their electricity bills. The volatility of retail pricing in a "deregulated" market will only be compounded by the increased emphasis on renewable portfolios and carbon reduction efforts. Arizonans already enjoy award winning utility service at prices that are among the lowest in the Southwest. SRP and New West Energy urge that the Commission not to take any action at this time to change the current system of providing electricity to Arizonans.

This is not to say that Arizona should remain stagnant. As we move into an era of alternative fuel sources and increased emphasis on conservation, the

[1] A.R.S. § 30-802(A) provides in relevant part: "Public power entities and the commission shall coordinate their efforts in the transition to competition in electric generation service to promote consistent statewide application of their respective rules, procedures and orders."

[2] A.R.S. 30-806(A) provides in relevant part: "Public power entities shall adopt rules and procedures to protect the public against deceptive, unfair and abusive business practices. Public power entities and the commission shall coordinate their respective rules and procedures to promote consistent implementation statewide."

[3] A.R.S. § 30-807(A) provides in relative part: "Public power entities and the commission shall coordinate their respective rules and procedures for public education programs to promote consistent implementation statewide."

Commission and the utilities should continue to explore methodologies, within the current structure, to provide retail users with options and alternatives.

II. ARIZONA'S DEREGULATION HISTORY

Electric industry deregulation was envisioned in a different time and place. In the early 1990s wholesale prices were low and the incremental cost of new capacity was below average cost. Against this scenario, economists advocated a theory that a deregulated electric industry would bring benefits to consumers, much like the deregulation of the airline or trucking industries. These economists envisioned a restructuring of the entire industry, from vertically integrated ownership (one company provides generation, transmission and distribution) to horizontal ownership (different companies own generation, transmission and distribution). This restructuring would allow unregulated competition within the generation sector, theoretically freeing market forces to produce lower prices.

California was the first to jump on the bandwagon, but Arizona was not far behind. Arizona debated and adopted a restructuring model that was the same in concept as California's:

1. The incumbent utilities would sell off (divest) their generation.
2. Transmission would be controlled by an independent system operator in a manner to permit open access to any generator.
3. Distribution would continue to be owned by the incumbent utilities, but now would be open to any generator on a non-discriminatory basis.
4. The buyers of the existing generation, and those who chose to construct new generation, would compete in both wholesale and retail markets, using the existing transmission and distribution systems.
5. Retail customers could choose a competitive generation provider on the basis of price or services.
6. The incumbent utilities would offer a standard price generation service, which would be phased out as competition matured.

Arizona's Retail Electric Competition Rules (R14-2-1601 *et seq.*) were adopted on December 31, 1998. The Legislature enacted complimentary laws for nonjurisdictional utilities in the 1998 legislative session (A.R.S. § 30-801 *et seq.*). Between 1998 and 2000 the Commission issued competitive certificates of convenience and necessity (permitting the holder to offer competitive electric service in the State) to approximately 32 companies (including New West Energy). The incumbent utilities, under order from the Commission and the Legislature, spent millions to retool their systems and to educate the public about the new ways of buying electricity.

Fortunately the Arizona experiment never got off the ground. Only a handful of customers had signed up with new electric providers when in the spring of 2000 disaster struck the Western electricity markets. The more mature "competitive" markets in California were producing very bad results.

The story of the spectacular failure of the electric markets in California has been often told. The now independent and unregulated generators freed market forces to produce wildly gyrating prices. While wholesale power was selling at three cents per kWh when competition was envisioned, between May and December of 2000, prices rose over 2000 percent. Federally imposed caps did little to stop the bleeding.

By the end of 2000 the State of California itself was signing long term generation contracts, the incumbent utilities were insolvent, the California Power Exchange was closing its doors, rolling blackouts were common, and criminal investigations had begun. Estimates vary, but between the costs of setting up the system and the losses of the failed markets, it is estimated that the restructuring experiment in California cost the state over $10 billion, without counting the collateral effect to the rest of the states in the Western markets.

III. RESTRUCTURING IS A DISCREDITED IDEA

A review of the literature, analyses and data compilations indicates that the root cause of the failure of restructuring lies in the unique attributes of the electric utility business. Attached to this paper as Appendix One is a compilation of some of the source material that forms the basis for the statements and conclusions of this Section III. Also supporting the factual assertions and conclusions is the testimony of Peter Fox-Penner and Frank Graves, of the Brattle Group, that was pre-filed in the Sempra CC&N docket (Docket No. E-03964A-06-0168) on August 31, 2007.

A. Unique Attributes of the Electric Industry

We begin with a discussion of the attributes of the electric industries that are different, collectively making the industry quite unique from any other.

1. Extreme Capital Intensity

The utility industry is the most capital intensive industry in the market place. The resources needed to enter this industry are quite substantial – and a significant natural barrier to entry. The ability to obtain large sums of capital is essential. This is not a simple task in the best of times. Creditors want assurance that there are buyers for the output, and that the debt will be repaid over a lengthy period of time. Buyers want low prices for electric service, meaning slow capital cost recovery over decades. Given the risk adverse climate of current credit markets, securing needed capital will be significantly more challenging. While access to credit is slowly improving, clearly the future cost of capital will be higher than during the previous periods of experiments with electric deregulation. Financiers will want a higher risk premium and will require more certainty that the output has a buyer.

2. Long Lead Times Compound Risks/Create Long Response Times

It is estimated that from permitting, through construction, to commercial operation, a coal fuel plant takes seven years, a combined-cycle natural gas plant takes five years, and a simple-cycle plant approximately two years. These estimates do not even include the time for planning and developing such large capital projects. This long lead time makes it extremely difficult for new entrants to survive long enough to get a positive cash flow, let alone recoup their investment. It also makes it nearly impossible for the industry participants to respond effectively to short term signals. Needs must be anticipated and committed to well in advance. Competitive markets do not work well in this sort of construct – they tend to either over react (as in the overbuild of gas generation in the California market) or under react (as in PJM's inability to get new generation or transmission built, even with capacity market price signals).

3. Few Opportunities to Effect Underlying Economics

One of the intended benefits of competition is to encourage innovation and new technologies that will improve the underlying economics of the product or service, and thus bringing the cost down. While experiments in electric deregulation have created winners and losers, there is no evidence that it has led to real technology or productivity improvements. In fact, the Cato Institute has concluded that empirically, "there is evidence that operational efficiency has decreased under restructuring." This is not surprising as technology innovation and adoption evolves relatively slowly in an industry which has such enormous capital costs and reliability requirements. It must be proven effective for companies to take the investment risk. The result is all players have access to the same portfolio of resource options and the same fuel resources at essentially the same costs.

4. The Value of Generation is Dependent on Transmission

All products require a delivery channel, but few require it instantaneously. You can produce oil or gas and store it for a period while fixing problems with a delivery channel. But generation assets can produce no electricity, and therefore no value, unless they have both transmission paths and a load to use the product. Even with an open transmission system, paths become congested and long distance transmission is expensive. Practically speaking, the market for generation is entirely dependent on the existence, cost and availability of transmission.

5. Generation is Not Mobile and is Limited to Small Markets

Electricity follows the laws of physics, not those of supply and demand. Given that generation facilities have little mobility, and distant delivery involves significant line losses, they are most efficient if they are located in relative proximity to the load that it intends to serve. Open access transmission systems provide some opportunity to reach new markets as circumstances change, but this inherent attribute naturally limits competition, regardless of transmission availability.

6. Reliable Electricity Supply is Essential to Life and Business

Unlike many commodities, frequent, wide spread, or prolonged interruption to the supply of electricity has immediate and profound impacts which are unacceptable to modern life and business. It is more than inconvenient. It undermines productivity, safety, and our very social fabric (as evidenced by looting that often accompanies wide-spread urban blackouts). Electricity has become essential to life, and must be available and affordable, even for those who cost more to serve. There is little room to tolerate the experimentation and related failures that typically accompany competitive markets.

A clear obligation to plan for and provide a reliable and affordable source of electricity is essential. Reliability means designing for a *consistent* state of *over* supply, a concept that is inconsistent with competition.

7. Wild Fluctuations in Price are Not Acceptable

Electric use cannot be deferred. Electricity is an essential commodity. Enabling people and businesses to plan over a relatively stable price horizon has significant value that is not easily measured. California demonstrated how electric markets can lend themselves to wild price fluctuations. Were it not for the temporary fixed retail prices that were in place at the time, California would have seen unprecedented retail fluctuations. Indeed, customers of SDG&E did experience swings of 200-400% as some of the market fluctuations passed to the retail level.

8. The Electric System is a "System": It is Integrated and Inherently Complex

The electric system requires advance planning and shared responsibility and accountability to work. Vertical integration is not simply a business theory. It is a requirement to make the electric system work and to keep it running. Attempts to separate the whole into parts also sever the links between risk and accountability for the system as a whole. (As evidenced by the 2003 blackouts in "competitive" east coast regions caused in large part by a breakdown in accountability and responsibility for the integrity of the system as a whole). Because of the essential nature of electricity, the need to provide power when and where it is needed, the need to locate relatively near the load, the need to construct new capacity against a long lead time, and the need to maintain excess capacity, advance planning is a part of the electric industry.

9. Opportunity for Multiple Market Participants Limited

Finally, even in a perfect system, the opportunity of real market participants (who own generation) is limited simply by the economies of generation. For the most part, the backbone of any system is large scale base or intermediate load generating units. As the economically viable number of these facilities is limited by demand, the number of potential for asset-based market participants is quite limited.

B. Issues Arising From Deregulation

Because of these inherent attributes of electricity and the electric markets, several issues inevitably arise when regulation is lifted.

1. Little Upside, Much Downside Risk

Though there are always claims of how deregulation will lower costs and unleash new value for consumers, there has been scarce evidence of such benefits in the experiments with competition. The historical reality is such benefits have occurred in regulated environments because of technology improvements that increased the efficiencies of generating facilities or that lowered the cost of fuel. (Such advances were prevalent in the 1950's and 1960's as power generation facilities benefited from improved materials and economies of scale, and again in the 1990's when improved efficiencies of combined-cycle units along with low cost natural gas created economics that favored new generation). What we have seen as regulations were removed is that potential "competitive" providers look to exploit the seams in the system. The result is a shift in costs from one group to another, not any real benefit to the system as a whole.

On the other side, downside risks are huge. The systems needed to manage these new markets and integrate with the complex and dynamic electric delivery system are hugely expensive. Mistakes have costly ramifications, as the experience in California demonstrated all too clearly. Most certainly prices will rise as new costs are injected into the system (e.g. the cost of risk capital and the cost of infrastructure for new participants). But more importantly, when participants' risks and responsibilities are separated from those associated with maintaining the integrity and economics of the system as a whole, there is no assurance that electricity will always be available, at any price.

2. Inability to Attract Capital to New Projects

In order to attract capital, financial markets demand some assurance of the ability to repay the investment, namely a future demand for the product. But in a deregulated market, there is no assurance of future demand for generation, because there is the possibility of multiple market entrants, especially given the lead times required to develop new generation facilities. The result will be that plants will not be built without a long term contract with a credit worthy retail provider. As a result, plants will be built to service the load of the distribution utilities or not at all leading to a scarcity of generation resources and price increases for consumers.

3. Unacceptable Retail Price Fluctuations

Marginal cost pricing sounded promising when it looked like the marginal cost of new generation would be lower than the average cost of existing generation. The reality is that the equation has flipped, exposing consumers to higher prices than traditional cost based pricing in addition to extreme price volatility. Moreover, because electricity is a good that is essential to life and business, it is highly price inelastic. It is thus unacceptable to leave retail electricity prices to an unregulated wholesale market.

4. Market Manipulation

If California taught us anything, it is that an unregulated market for an essential and inelastic good creates opportunities for criminal behavior and the efforts to monitor and manage against such behavior creates expensive new layers of bureaucracy.

C. The Major Obstacle - The Provider of Last Resort Obligation

Perhaps the most vexing and fundamental issue arising from deregulation is the ability to fairly and effectively ensure there is a provider of last resort ("POLR"). The POLR is the utility that assures that adequate system capacity is available to serve all of its retail load, even load served by competitive providers. It is the POLR that assures that sufficient capacity for the system is built and maintained (avoiding the wholesale price run ups when demand exceeds supply). It is the POLR that insures long term planning. Thus the POLR plans and builds the generation mix needed for long term stability. It is the POLR who brings stability to the retail markets by providing a baseline price (sometimes called standard offer service) to mitigate retail price spikes. And, ideally the POLR assures that long term programs for renewable resources and carbon emission reductions are in place.

But the provider of last resort service comes with a steep price, as long term planning and capacity maintenance is one of the most expensive aspects of the utility business. The failure of all the experiments in the other states devolves to the reluctance to recognize and pay for the POLR costs. Thus we see artificially frozen retail prices, with the resultant eventual spikes, or worse yet, the financial failure of the provider. We have seen wholesale prices spin out of control because of inadequate capacity. We have seen poor system planning as competitors all build the cheapest, fastest to market, capacity available. And, we have seen a lack of fundamental and integrated demand side management and integrated planning programs.

The position of SRP and New West Energy are supported by the testimonies of Frank Graves of the Brattle Group, that was prefiled in the Sempra CC&N docket on August 31, 2007 (Docket No. E-03964A-06-0168). Dr. Graves, particularly addresses the essential importance of providing POLR service in a restructured market. Dr. Graves points out that Arizona does not have in place a system that in any respect can be considered adequate:

> [The lack of adequate POLR service] has impeded the development of a pool of competitive ESPs, and in some cases it has imposed large, uncompensated financial risks on utilities providing the service. For SOS [Standard Offer Service] to avoid

> these pitfalls, all the major elements of its design must be carefully and consistently specified, including customer class differentiation, switching rights, term (horizon), pricing rules, procurement mechanisms, and regulatory approval guidelines. This has not yet happened in Arizona. In particular, existing generation tariffs were not developed with the intent or effect of compensating the utilities for the costly risks associated with customer switching. Thus, these prices do not provide a fair or efficient SOS price for prodigal ESP customers.

Graves Testimony p.5:1-11.

Dr. Graves totally dispels the idea that Arizona has already addressed the issue:

> POLR is a different, more complicated service than simply serving franchise customers with embedded generation, and its design, pricing, and procurement mechanism need to be specified in advance of allowing ESPs to begin serving customers. This has not yet happened in Arizona. Instead, the existing tariffs for generation service are being described as if they are the POLR service.

Graves testimony, p.11:6-11. Dr. Graves explains that the Arizona system is inadequate:

> At present in Arizona, the tariffed rates for utility customers [purport to provide POLR protection], but those rates were not set with the intent or effect of compensating the utilities for bearing customer-switching risks. As discussed above, the required premiums can be significant. Instead, these are cost-of-service rates set to reflect generation accounting costs and a fair return on the underlying assets in a non-switching environment. If/when ESP customers switchback to this utility service, that can only occur at the expense of utility financial losses or increased costs to other customers who did not switch. Both outcomes are unfair and inefficient. Thus, these tariffed services should not provide comfort to the ACC about the just-and-reasonableness of ESPs' proposed maximum prices.

Graves testimony, p.17:18-23.[4]

[4] Note that the provider of last resort obligation does not exist at all for customers of public power entities who use more than 100,000 kWh per year. A.R.S. § 30-806(I).

Dr. Graves concludes:

> To my knowledge, virtually none of the several prerequisite steps involved in retail market design have yet transpired in Arizona: As a result, customer classes may have constituents with extremely different marginal costs, making them prone to cherry picking. The current generation services from utilities were not crafted or priced with POLR risks in mind, so they do not provide a suitable backstop service. Questions about how much risk to include in the price of POLR (e.g., some degree of real-time pricing) have not been debated, and the tension between Integrated Resource Planning and customer choice has not been fully recognized. The enabling legislation and law seems to require a review of ESP tariffs and profitability that is not well-defined and which could be counterproductive. Criteria for monitoring and evaluating the performance of retail market competition are not in place.
>
> In short, there seem to be many aspects of this complex problem that have not yet been adequately considered. . . . Perhaps there is a lack of awareness of these issues, or perhaps there is a presumption that they were all well-vetted initially and we have simply been waiting for a more auspicious time to apply those prior insights. I would suggest that that is unlikely, given how much we have learned in other settings about the difficulties in getting retail access to work well. Failure to address these prerequisites before opening the doors to retail choice is likely to result in Arizona repeating the mistakes of others.

Graves Testimony, pp.29:10 – 30:4

It is undetermined whether a "competitive" market can co-exist with a true provider of last resort responsibility. As discussed below, certainly the concept has yet to be proven.

IV. THE RESULTS OF THE EXPERIMENTS

Various states have tried different schemes to try and address these inherent issues, all to no avail. Here are some of the high profile examples.

California

The California Model

In 1996, California adopted the classic restructuring model: it separated generation from an obligation to serve and left generation prices largely to an unregulated wholesale market. By 2000 over 80% of the generation used by California customers was sold and purchased in unregulated markets.

What happened?

There was no central control of supply and little control of wholesale market price. Thus, when demand exceeded the finite supply, prices rose almost without limit. Because of the inadequate supply, California retail customers were left, at times, without an adequate supply of electricity. To firm up supply, the State was forced to purchase electricity itself, under very expensive long term contracts. In early 2001 the State closed its power exchange, froze its direct access program, and basically retreated to regulated vertically integrated service. The result was a loss of many billions of dollars to the people of California.

Current Status

Not surprisingly, large industrial customers who profited in the short term from the disaster seek to restart "deregulation". In December 2006, a petition was filed with the CPUC by the Alliance for Retail Energy Markets and over two hundred other co-petitioners and supporters, asking they open an investigation into the continued suspension of the right to direct access and choice in energy suppliers. The CPUC continues to evaluate the petition, against fierce opposition from consumer and industry groups.

Texas

The Texas Model

"Deregulation" began in Texas in 2002, with utilities being required to unbundle into three separate categories: (1) generation, (2) distribution, and (3) transmission. Retail prices were artificially frozen for three years.

What happened?

The results thus far have not been good:

- New generation plants have tended toward those that are cheap and quick to build. This has moved Texas toward a system dominated by peaking capacity, resulting in higher fuel and operating costs.
- Allegations of market manipulation have been many. Texas PUC Staff, recommended a $210 million fine against what was one of the State's largest utilities, TXU.
- Prices have risen at a very quick pace. It is estimated that prices have risen over 56% since 2002. A study recently released by the Texas Coalition of Cities for Utility Issues says "even the very lowest competitive rate available to millions of Texans is still higher than rates enjoyed by Texans served by fully regulated utilities, cooperatives and municipally-owned utilities."
- Competitive providers are dropping out. "Already, high spot-market prices have pushed five electricity retailers, serving about 45,000 customers, into default. More defaults are possible because many retailers are small companies working on thin margins. When retailers go under, customers' lights stay on as their accounts are switched automatically to "providers of last resort" -- nearly always with higher rates. Many customers don't find out about it until their next bill."
- Costs for managing the transmission system to facilitate "competition" have run way over budget, with no end in site. The Electric Reliability Council of Texas "is more than 100 percent over budget and two years behind schedule on its ongoing program to modernize the transmission system. ERCOT recently disclosed that in addition to the costs to establish and maintain the system, it expects to spend $660 million alone to implement a system that divides the transmission network into thousands of 'nodes' rather than the current five zones.

Current Status

Texas is currently deregulated, although PUC Commissioner Barry Smitherman said, "[O]ne more false move by an electricity company could spark a backlash against the competitive market, leading to reregulation of the industry."

Pennsylvania

The Pennsylvania Model

Under the Pennsylvania model, customers were protected by an artificial rate freeze that extends through the end of 2010. Currently the PUC is considering plans to mitigate the impact of the significant price increases expected when the rate cap ends, including significant consumer education programs to help customers prepare for coming increases.

What happened?

An artificial rate cap does nothing more than delay the inevitable. The result is a massive and unexpected sudden price increase. For example the customers of Pike County Light and Power, who were subject to an early end of the rate cap, saw their prices rise by 73%. It is estimated that when the cap ends for the State's largest utility, PPL Electric Utilities Corporation, prices will rise by at least 35%.

On the competitive provider side, the 84% increase in wholesale rates between 1998 and 2001, combined with price caps, made it difficult for alternative suppliers to compete with utilities. The number of alternative suppliers dropped from 30 to under 10 in the period of 1998 to 2001.

On the consumer side, a December 2008 report by the PUC found that gas and electric shut-offs have climbed dramatically since a 2004 law made it easier for utilities to stop service to non-paying customers. Assistance programs for those unable to pay bills, funded by rate payers, have grown to $330 million, or $45/year/residential customer. In the current environment, PPL and other energy companies can't justify taking on the financial risks of building much-needed new power plants. At the same time, consumers, shielded from higher prices, don't have as much incentive to conserve energy. The worst-case scenario, according to PPL CEO James Miller, is that PPL would be unable to charge customers enough to recoup its expenses and meet its own financial obligations, resulting in bankruptcy.

Current Status

Pennsylvania is currently "deregulated" and has retail choice, though price caps are still in place for most customers through 2009 or 2010.

Maryland

The Maryland model

Maryland phased-in deregulation with 33% of customers in 2000, 66% of customers in 2001 and 100% of the customers in 2002. The legislative plan mandated a rate reduction followed by a rate freeze.

What happened?

During the winter of 2005, the market-based cost of electricity skyrocketed in the wholesale electricity auctions. In July 2006 the market-based cost of electricity for an average residential customer increased 72% in the Baltimore Gas and Electric service territory. Increases of 35% and 39% occurred in services territories covered by Delmarva and PEPCO, respectively. Although Maryland consumers have an option to change electric service providers, "Maryland's customers have not switched from their default service provider to competitive suppliers."

Current Status

Since 2006, there have been numerous attempts to re-regulate or ease price increases. The General Assembly attempted to depose the Public Service Commission, but was overturned by the State Court of Appeals. In May 2007, the General Assembly passed a bill that requested the Public Service Commission "reevaluate the general regulatory structure, agreements, orders, and other prior actions of the Public Service Commission under the 1999 Maryland Customer Choice and Competition Act". The newly passed bill also requested the "determination of and allowances for stranded costs" and to "conduct hearings" as part of its evaluation of the 1999 Settlement. Today, Maryland remains deregulated and has retail choice. (note: Maryland has decided that it would be too expensive to "reregulate".)

<u>New York</u>

The New York Model

Deregulation began in 1997 through a Public Service Commission decision. Through 2001 deregulation was implemented in phases by company and/or by customer. In 1999, metering was unbundled for all large customer classes and/or industry segments.

What happened?

With no single entity responsible for supplying power to the consumers of New York, plant operators have been reluctant to assume the risks that come with new generation, citing environmental concerns over emissions that may be a liability in the future. Although there have been capacity expansions since the deregulation inception, levels of expansion are not adequate. This, combined with a transmission system that was not designed for a competitive market, results in the overuse of outdated and inefficient generation, including century old steam turbines.

Under the New York system, electric service providers are required to pay the same price to all plant operators – the marginal cost of electricity. When inefficient, century-old plants are being utilized, that marginal cost is much higher than when newer, efficient plants are being used. Congestion charges, rooted in the inability of the New York system operator to properly handle the transmission system in a way that is competition-compatible, have been pegged at $90 per New York City resident annually.

Additionally the state regulatory commission is investigating a possible scam that saw energy-market traders use deceptive routing practices in order to avoid higher transmission costs.

Power in the Public Interest wrote, "In 2000, the average price for all customers in New York was 10.6 cents/kWh; the comparable figure for the collective regulated states was 6 cents/kWh—or a difference of 4.6 cents. As of June 2007, the difference had widened to 6.8 cents (14.5 cents/kWh for New York and 7.7 cents/kWh for the regulated states). For the 12 months ending June 2007, New Yorkers paid $22 Billion for their electricity. The same amount of electricity at the regulated states' average rate would have cost $11.6 Billion—a difference (or comparative purchasing-power disadvantage to New Yorkers) of $10.4 Billion for a 12-month period".

Current Status

New York is currently deregulated. However, state legislators are actively working to end the current system.

Virginia

The Virginia Model

In December 2001, the Virginia State Corporation Commission ("SCC") directed each utility to maintain separate divisions along functional lines for the generation, transmission and distribution functions. The incumbent utilities will continue to provide delivery service for all customers and default service for the customers who do not choose an alternative provider. Prices are currently capped through 2010.

What happened?

About a dozen competitive suppliers are licensed to market electricity to Virginia customers. But for now they are "sitting on their licenses" as it is almost impossible for anyone to compete against the prices produced by regulated service.

Current Status

Dominion Virginia Power's plan to give the State more control over utility rates and shield Virginians from the kind of power bill spikes seen in states that have opened their retail electric markets to residents signals the end of deregulation in

Virginia. The SCC in a report last year declared that the State had made little progress in creating healthy electric competition. "The right to choose has still not evolved into the ability to choose," SCC staff wrote. In addition, the SCC had concerns that deregulation would lead to significant cost increases for consumers when the rate caps in the law expire.

V. WHERE WE ARE IN ARIZONA

Arizona is in an enviable position. Its customers enjoy award winning service and some of the lowest prices in the Southwest. Arizona utilities continue to develop new and innovative pricing structures and renewable options.

A. Award Winning Service

For, example, Salt River Project is a consistent winner of the JD Power Award for excellence in customer service. Over the past ten years Salt River Project received these awards:

J.D. Power Residential Service

*1999 - SRP first in the West
*2000 - SRP first in the West (first in the nation)
*2001 - SRP second in the West (one point behind TEP)
*2002 - SRP first in the West
*2003 - SRP first in the West
*2004 - SRP first in the West (first in the nation)
*2005 - SRP first in the West
*2006 - SRP first in the West (first in the nation)
*2007 - SRP first in the West
*2008 - SRP first in the West (second in the nation)

The business study was expanded in 2004 to include utilities like Salt River Project. Since that time:

*2004 - SRP first in the West (first in the nation)
*2005 - SRP first in the West

*2006 - SRP first in the West

*2007 - SRP fourth in the West, tenth in the US

*2008 - SRP third in the West, tenth in the US

B. Favorable Retail Prices

In addition to enjoying award winning service, Arizonans enjoy some of the lowest prices in the Southwest. Below is a chart comparing Arizona retail residential prices and all prices against those of other Southwest regions.

RATE COMPARISON BY REGION, cents/kWh

REGION	RES. AVE	TOTAL AVE
SO. CALIFORNIA	14.46	13.32
NEVADA	12.14	11.28
ARIZONA	10.45	9.68
COLORADO	10.07	8.62
NEW MEXICO	9.64	8.48
SRP	9.49	8.33
UTAH	8.24	6.21

C. Vast Array of Choices Currently Available to Customers

Additionally SRP offers a very large array of choices and options to its customers. In consultation with its customers SRP continually updates these options and offers, to better meet customer expectations and needs. Choices and options include:

Options to standard price plans:

E-20: An experimental super peak TOU price plan.

E-24: The M-Power plan, which is an optional pre-pay price plan for residential accounts, is the largest of its kind in North America.

E-26: This is an optional TOU price plan for residential accounts.

E-28: This is an optional "M-Power" pre-pay time of use price plan for residential accounts.

E-32: An optional time of use price plan for commercial accounts.

E-34: an optional "M-Power" pre-pay price plan for commercial accounts

E-48: An optional off peak price plan for commercial and municipal pumping accounts.

E-57: An optional plan for unmetered lighting applications including private residences, commercial applications and other lighting applications.

E-61: An optional time of use plan for accounts with a monthly consumption in excess of 300,000 kWh for three consecutive months that are metered at the secondary voltage level.

E-63: A time of use plan for accounts with a monthly consumption in excess of 300,000 kWh for three consecutive months that are metered at the primary voltage level.

E-65: This TOU price plan is for accounts with a monthly consumption in excess of 300,000 kWh for three consecutive months that have dedicated or customer-owned substations.

Available riders to standard price plans:

Renewable Energy Credit Pilot Rider: This rider allows customers to obtain Renewable Energy Certificates (REC's) from SRP. REC's are associated with energy generated from sources that may include, but are not limited to, solar biomass, landfill gas, wind, geothermal or small hydroelectric.

Buyback Service Rider: This rider allows customers with onsite generation to sell power back to SRP using a market-indexed price, less a transaction fee.

Solar Net Metering Rider: This rider nets solar generation against a general service customer's total energy usage for systems of 20 kW or less. This rider is intended to encourage installation of solar electricity conversion systems.

Energy For Education Pilot Rider: This rider is intended to assist schools with replacing or retrofitting equipment so that the schools use less electricity and therefore save on operating costs. Under this limited pilot rider, SRP allows the customer to pay for the capital cost of the equipment over time.

EarthWise Energy Rider: This rider is for customers who are interested in supporting the development of local renewable resources. Customers voluntarily pay a $3 per-month premium per block to support the EarthWise Energy program.

EarthWise Energy Rider For Large Customers: This rider is similar to the EarthWise Energy Rider, but it allows for a discounted payment for EarthWise Energy blocks for large subscriptions.

Time-Dependent Demand Riders: These riders, for E-36 and E-47 price plans, allow customers to have the peak demand used in calculation of the demand charge to be based on the highest demand recorded during the on-peak period.

Critical Peak Experimental Price Plan: This plan is supplemental to E-65 and features a reduced on-peak price on "standard" days and a higher on-peak price during peak hours for "critical peak" days.

Standby Electric Service Rider For Power Production Facilities: This rider applies to qualified cogeneration and small power production facilities equal to or greater than 3,000 kW.

Facilities Rider: This rider include: 1) an average distribution facilities charge for customers taking service from SRP's general distribution system; and 2) a customer-specific charge for substation service.

Use Fee Interruptible Rider: This rider offers credits to customers in exchange for the customer curtailing load.

Instantaneously Interruptible Rider: This rider credits customers for the right to interrupt their load, without notice, for reliability purposes.

Interruptible Rider With 10 Minutes Notice: This rider credits customers for the right to interrupt their load, with ten minute notice, for reliability purposes.

Customized Interruptible Rider: This rider is available to customers who agree to be interrupted at terms and prices not currently available under other programs.

Full Electric Service Requirements Rider: This rider provides a discount for customers with at least 1 MW of load who elect to sign a service contract.

Monthly Energy Index Rider: This rider provides an average monthly energy charge, based on firm market prices at Palo Verde.

PowerWise Programs

Standard Business Solutions - promotes the purchase of industry-proven, high-efficiency equipment. Rebates are available for qualifying lighting, HVAC, motors and variable frequency drive measures.

Custom Business Solutions - provides a comprehensive platform for cost-effective non-residential energy efficiency projects such as chillers, process improvements, and energy management systems.

Large Business Solutions - provides large customers technical service support to identify and quantify energy savings opportunities.

Compressed Air Solutions - provides technical support and rebates to identify and implement energy conservation practices in existing commercial and industrial compressed air systems 100 HP and larger

Cool Roof Solutions - program focus on providing rebates for customers that install a qualifying cool roof on an existing building.

Rebate Programs

In addition to these many service options SRP offers rebate plans to encourage energy efficiency. These include:

Lighting rebates: $0.20/Watt of reduced demand

Motors and Variable Speed Drives: $2.00 to $30/Horsepower

A/C Retrofit: $50 to $100/Ton

Custom Energy Efficiency: $0.11/annual kwh savings - first year

Energy Studies: Preliminary $3000, technical 50% up to $15,000

Compressed Air: $0.11/annual kWh savings

Cool Roof: $.05/square foot

Demand Response: Eneroc 20-30 MW; Begin FY2010

Photovoltaic: $2.50/kW DC, Capped at $500,000, Adjusted based on performance

Solar Hot Water: $0.50/kWh for 1-year metered energy production, not to exceed 60% system cost.

Solar Pool Heating: $0.50/kWh of 1st year metered energy production, not to exceed 60% system cost.

Compact Fluorescent Lighting: Discounts at participating retailers.

Appliance Recycling: $30 and pick up of working refrigerators for recycling.

High Efficiency Washers and Dishwashers: $20 for qualified dishwashers, $50 to $75 for qualifying washers.

Solar Hot Water: $0.50/installed kWh of energy savings

Photovoltaic: $3/Watt up to $60,000.

VI. CONCLUSION

What would it hurt to give some customers a choice of retail electric service providers? The lessons of history have taught us that those few customers who switch will not be receiving new value, but will simply be exploiting seams in the system, to the detriment of other customers. Here are some examples of the issues that will arise if some customers are given "choice" over a system of regulated vertically integrated service:

1. There will be no planning for the future of any customer who has the right to switch. Yes, the provider of last resort obligation could be provided by incumbent utilities, or bid out. But, the true cost of constructing and holding capacity to serve customers, who may or may not be taking service, is prohibitive.

It can be argued that a customer "comes back" at its own risk. The consequences may be high prices or no service at all. But, this is not realistic. Politically our state will not let major businesses close for lack of electric capacity planning. The bottom line will be that all customers will share in the cost of maintaining the capacity needed to re-serve customers looking for short term benefits (at the expense of other customers).

This issue alone, as supported by the testimony of Frank Graves, is enough to strongly conclude that restructuring is not now in the public interest.

2. Even if capacity is constructed for "competitive" customers, it will not be effectively integrated with the resource plan for the region. We have seen in other states that the tendency is to build cheaper gas-fueled facilities. But, proper planning of the system requires a mix of more expensive base load and intermediate load resources, as well as integrated renewable resources. While cheap resources may work in the short term, the long term is detrimental to the system, system operation and system costs.

3. The risk of market manipulation increases. Even if some of the system is subject to regulation, the deregulated part of the retail load presents opportunities for market manipulation. This is particularly true where competitors are buying from the market, rather than devoting their own resources to retail customers. While wholesale markets are now more stable than in the past, there is no assurance that the same defects that produced the California energy crisis in 2000 are gone.

4. Overall costs will increase. As mentioned, real economies are difficult to achieve. Yet, multiple vendors produce duplicate costs, increasing the costs of the system as a whole.

5. Price volatility will increase. Additionally, the volatility of retail pricing in a "deregulated" market will only be compounded by the increased emphasis on renewable portfolios and carbon reduction efforts.

6. Participation of competitive vendors in renewable programs will be questionable. It will be difficult for the Corporation Commission or the State of Arizona to cooperatively work with multiple out-of-state vendors to address the renewable needs and goals of Arizona.

7. Demand side and conservation initiatives will suffer. The most effective method of furthering the conservation goals of Arizona is through cooperative efforts among the State's utilities, businesses and governments. "Deregulating" retail service will be a move away from the objective of cooperative action.

8. The rules and laws that formed the basis of "deregulation" in the late 90s contemplated a complete restructuring of the electric industry in Arizona. Because of lessons learned, the Commission and the Legislature never implemented the restructuring. Now it is proposed that the industry be partially restructured. But, what does this mean? How is vertically integrated regulated service to be integrated with some unregulated market components? What will be the new structure? It is clear that if something is to be done, a serious effort will be needed to develop exactly what will be the new structure, then to develop rules and laws to implement it.

9. Finally, it is likely that a resumption of "deregulation" will create prolonged legal disputes, as occurred following the initial enactment of the Arizona competition rules. The Phelps Dodge case held that the Constitution requires that the Commission consider "fair value" in determining reasonable rates and charges. But, what does this mean? Is it enough that a potential market entrant simply provide a summary balance sheet of local office assets (as did Sempra in its application). Or does the fair value concept carry with it some more substantive requirements and corollaries?

The compelling answer is that Arizona should continue to watch the development of experiments in other states, protecting its economy and being content with the great benefits that it now receives from the current structure of the electric industry. As former Commissioner Mike Gleason said, Arizona should not be first, but should wait to see if any successful models are demonstrated elsewhere.

APPENDIX ONE

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