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BEFORE THE ARIZONA CORPORATION COMMISSION

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

COMMENTS OF RETAIL COMPETITION ADVOCATES AND THE RETAIL ENERGY SUPPLY ASSOCIATION ADDRESSING RETAIL ELECTRIC COMPETITION ISSUES[1]

July 15, 2013

Arizona Corporation Commission
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[1]The joint comments herein filed by Direct Energy Services LLC, Constellation NewEnergy, Inc. and Noble Americas Energy Solutions LLC ("Retail Competition Advocates") and the Retail Energy Supply Association ("RESA") are provided in response to questions contained in the letter filed by Ms. Jodi Jerich, Executive Director of the Arizona Corporation Commission dated May 23, 2013, In the Matter of the Commission's Inquiry into Retail Electric Competition, Generic Docket No. E-00000W-13-0135. Furthermore, the filing of joint comments by these parties was based upon these parties holding the same position as to the appropriateness of resuming Electric Competition in Arizona and for ease of review by the Commission for their consideration.

COMMENTS
E-00000W-13-0135

PART 1 OF 5
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I.

INTRODUCTION

Constellation NewEnergy, Inc., Direct Energy Services, LLC, Noble Americas Energy Solutions LLC, (collectively "Retail Competition Advocates")[2], and the Retail Energy Supply Association ("RESA")[3] commend the members of the Arizona Corporation Commission ("ACC" or "Commission") for moving forward on the important issue of retail electric competition in the state. Other state jurisdictions have wisely created markets to allow their residents and businesses the freedom to choose their electricity supplier and to benefit from the competition that such choice creates. Indeed, it is no exaggeration to say that informed parties from all over the United States are watching Arizona with optimism that the Commission will act expeditiously in supporting retail competition to ensure Arizonans also benefit from electric choice.

Retail electric competition and customer choice are long overdue in Arizona. Customers are being denied both savings and service innovation the longer they are limited to monopoly providers and bundled tariff services. The Commission has quite properly decided to re-evaluate retail electric competition in light of more than a decade of customer choice success in other states.

Retail Competition Advocates and RESA appreciate the opportunity to participate in this first phase of this proceeding, initiated by ACC Executive Director Jodi Jerich's May 23, 2013 letter ("Request for Comments"). We anticipate that this process will expeditiously culminate in a decision by the Commission to move forward to re-institute electric retail competition. The comments of the Retail Competition Advocates and RESA will reference the substantial evidence that demonstrates that retail electric choice has placed downward pressure on electric prices, stimulates innovation and efficiency,

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[2] Each of the members of the Retail Competition Advocates have applications pending before the Arizona Corporation Commission for Certificates of Convenience and Necessity, which will, when approved, allow each to compete to provide retail electric service to Arizona customers. We anticipate that additional appplications will be submitted when the Commission moves forward with retail electric competition.

[3] The Retail Energy Supply Association (RESA) is a broad and diverse group of retail energy suppliers operating in 16 states delivering competitively priced retail electricity and natural gas to residential, commercial and industrial energy customers. For information about membership and initiatives, see: http://www.resausa.org/ RESA's members include: AEP Energy, Inc.; Champion Energy Services, LLC; ConEdison Solutions; Constellation NewEnergy, Inc.; Direct Energy Services, LLC; GDF SUEZ Energy Resources NA, Inc.; Hess Corporation; Homefield Energy; IDT Energy, Inc.; Integrys Energy Services, Inc.; Just Energy; Liberty Power; MC Squared Energy Services, LLC; Mint Energy, LLC; NextEra Energy Services; Noble Americas Energy Solutions LLC; NRG, Inc.; PPL EnergyPlus, LLC; Stream Energy; TransCanada Power Marketing Ltd. and TriEagle Energy, L.P. The comments expressed in this filing represent the position of RESA as an organization but may not represent the views of any particular member of RESA.

and empowers customers to choose products and services to meet their individual needs – to the benefit of all customers.

Retail Competition Advocates and RESA are confident that after the Commission and the ACC Staff review the responses to the Request for Comments provided by all interested parties, it will conclude that implementing retail choice in Arizona is in the public interest and all initiatives necessary to support that outcome must commence.

As such, it is the Retail Competition Advocates' and RESA's hope that the Commission will direct ACC Staff to:

- Develop and/or modify existing retail market rules and protocols to ensure an efficient and robust competitive market framework; and

- Address and remedy the technical and legal deficiencies that resulted in the rules being suspended, as was contemplated by the Commission at the Open Meeting held on March 9, 2013.

Retail Competition Advocates and RESA have structured responses to the questions posed in the Request for Comments to provide the Commission with ample evidence and support for the resumption of retail electric competition by:

- Recounting the growing body of evidence on the benefits of retail choice and the various ways that a market can be structured to achieve favorable outcomes for all consumers. A compendium of reports and resources (Attachment A) is included that documents the successes and "lessons learned" from other retail choice markets, the benefits choice brings to residents and businesses, and a description of market design approaches that have been pursued in other markets to date to ensure the transition to retail choice is best designed for customers. Many of these reports are specifically cited in these comments; others are included because of their relevance to the matters at hand and will provide the Commission and Staff with additional description and data on the implementation of retail electric choice.

- Explaining the mechanisms by which Provider of Last Resort service will be made available to customers and how those mechanisms prevent cost shifting; and

- Providing an overview of the important and manageable work that will be necessary in Phase 2 of this proceeding to re-establish retail market rules and protocols.

II.
Responses to the Questions Posed in the Request for Comment

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

Response: The benefits of robust, sustainable retail competition extend beyond a simple analysis of price. With retail competition, customers are empowered to choose among a number of value propositions customized to their individual needs. In some instances, that may be an evaluation solely on price, but for others it may be about increasing their use of renewable energy, or a desire to have a fixed price in place for a pre-determined period of time, while still others may prefer time differentiated prices or some blend of fixed and variable pricing. The full range of customer choice benefits should be evaluated in their entirety; savings is but one of those benefits.

The success of competition in reducing electric rates to their lowest possible levels in both the retail and wholesale sectors of electric industry has been well documented. Many of these data points are cited below and demonstrated by a wide range of reports, analysis, and data summarized in the Attachment A compendium. The corollary point is, of course, that the Arizona *status quo* of vertically integrated, rate-regulated utility service has not and will not guarantee any of these benefits to consumers. Proponents of the *status quo* – opponents of customer choice – should be expected to make an affirmative case for the superiority of customer savings and services under the *status quo* approach, arguing that the empirical evidence of restructured market successes are somehow not appropriate for Arizona to consider. Retail Competition Advocates and RESA note that every state commission that has pursued restructuring has asked a similar, fundamental question, "Will the benefits of retail competition to residents and businesses in our jurisdiction outweigh the risks of pursuing this market approach?" We submit that, for Arizona, the answer to this question is a resounding yes. Our responses that follow address why moving to a Phase 2 implementation discussion in this proceeding is warranted, and will be beneficial to all classes of customers in Arizona.

Currently, seventeen U.S. states plus the District of Columbia allow full or partial customer choice, leveraging a range of models. As a result, approximately 20% of all energy sales (TWh) in the U.S. are served competitively by a supplier other than the vertically integrated utility.

Success of Competition in Retail Electric Markets: Allowing customers to make choices with respect to their electricity supply will create competitive pressures that incentivize more efficiency, technological innovation, product innovation, and better risk management, and that will inherently put downward pressure on prices. In fact, reports by several state utility commissions document that prices in competitive markets are lower than would have been the case in a rate-regulated environment, had those states not restructured. Those reports are included in Attachment A to these comments.[4]

[4] Attachment A: Ref #A1, "Regulation and Relevancy: Assessing the Impact of Electricity Customer Choice"; Ref #A8, "Retail Electric Choice: Proven, Growing, Sustainable"; Ref #A10, "Retail Electricity

When considering what constitutes "success" in competitive retail markets, the evidence suggests the following metrics are important to evaluate:

- **The Exercise of Customer Choice** (*Are customers actively engaged in taking advantage of the choices they are afforded and at what prices?)*
- **Customer Value and Savings** (*Are customers able to select alternatives to the traditional bundled rate that afford them savings or additional product choices?*)
- **Abundant Product and Service Options** (*Has the competitive market resulted in a variety of products and prices from which customers can choose?)*
- **Market Entry and Participation of Retail Suppliers** (*Has the competitive market design attracted a substantial/increasing number of competitive suppliers to participate in the retail markets?*)

The following offers an overview of the experience with regard to each of these measures in restructured markets to date.

The Exercise of Customer Choice

Customers in open retail markets are actively choosing a supplier of their electricity other than the traditional vertically-integrated utility at increasing levels. Each restructured state reports (typically monthly or quarterly) customer choice activity statistics by utility territory and customer type. The market design (particularly regarding the procurement and pricing of default service where it exists), along with customer education initiatives and other retail rules such as "purchase of receivables" and aggregation allowances, greatly contributes to variations in residential shopping across markets. The following examples highlight customer choice activity from the most recent utility commission reports.

- **Residential migration to competitive supply:** In addition to Texas (where choice is 100% in the areas of Texas where choice is allowed, since customers can only opt for a competitive retail energy provider by market design), there are numerous examples where a restructured state's market design has led to a significant number of residential customers choosing a competitive supply option, including:
    - Illinois: As a statewide average, over 60% of Illinois customers have chosen a retail supplier. There is some variation in Illinois utility territories based on tariff and market design. The highest residential choice rates are in Ameren (Central Illinois Light Co.) at 73% residential migration to a competitive supplier; 67% in Commonwealth Edison's territory.[5]

Customers Benefit When Suppliers Compete to Serve Them"; Ref #A14, "Innovation in Competitive Electricity Markets"

[5] Based on the latest data available from the Illinois Commerce Commission (ICC) @ http://www.icc.illinois.gov/electricity/switchingstatistics.aspx

- Ohio: Three utility territories in Ohio report residential customer migration to a competitive supplier over 70%: Cleveland Electric and AEP both report 76% migration, and Toledo Edison reports 72% migration.[6]
- Pennsylvania: Residential customer choice in Pennsylvania utility markets ranges from 28% (West Penn Power) to 45% (Duquesne Light).[7]
- Connecticut: United Illuminated reports 49% of customer accounts competitively served; Connecticut Light & Power reports 44% residential customer choice.[8]

- **Non-residential migration to competitive supply**: Competitively-served non-residential volumes served in MWh, as a percentage of eligible MWh in restructured markets, average over 80% across all utility markets, with some larger industrial volumes competitively served over 90%.[9]

Customer Value and Savings

According to an analysis of data from the U.S. Energy Information Administration and the Bureau of Labor Statistics, between 1997 and 2012 inflation-adjusted retail rates in states with restructured competitive retail markets decreased by 4% while those in states that rely on monopolies increased 7%. Retail customers in all classes have benefitted from these decreases. Specifically, inflation-adjusted rates for residential, commercial, and industrial customers in retail choice states decreased by 6.5%, 12.1%, and 1.7%, respectively over this period, while rates in these same customer classes in monopoly utility states increased by 3.9%, 1.2% and 10.1%, respectively.[10]

Abundant Product and Service Options

Customers in restructured power markets have a wide range of offers to choose from, such as various contract durations, pricing options, renewable options, as well as other value added products and services, such as energy efficiency services. Finding creative ways to use technological and other innovations is a core competency of competitive retailers and the best way to make these solutions available to customers is through a robust competitive retail market. Tables 1 and 2 that follow summarize just a

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[6] Based on the latest data available from the Public Utilities Commission of Ohio (PUCO) @ http://www.puco.ohio.gov/puco/index.cfm/industry-information/statistical-reports/electric-customer-choice-switch-rates/

[7] Based on the latest data available from the Pennsylvania Office of Consumer Advocate (OCA) @ http://www.oca.state.pa.us/Industry/Electric/elecstats/ElectricStats.htm

[8] Based on the latest data available from the Connecticut Department of Public Utility Control (DPUC) @ http://www.dpuc.state.ct.us/dockhist.nsf/Web+Main+View/Search+Electric?OpenView&StartKey=06-10-22

[9] Each state utility commission in restructured markets reports its non-residential customer choice activity, in different non-residential size categories If the Commissioners or Staff would like more information on non-residential customer choice activity details than is shown here, Retail Competition Advocates and RESA will be glad to provide as a supplement.

[10] Attachment A: Ref #A2, "States with Restructured Electricity Markets Post Lowest Rates of Change"

sample of competitive residential offers in restructured markets, which are publicly reported on either a state commission, utility, or external offer comparison website. Both tables include a column (labeled "Price to Compare") which is each utility's residential default rate that customers pay if they do not shop.

Specifically, Tables 1 and 2 show, for one representative month – June 2012- the average among all residential pricing offers (as well as the minimum and maximum offers of retail suppliers) in each utility territory for the nine states where this competitive information is publicly posted.

- As Table 1 shows, residential customers in nine states had from 3 to 58 different fixed or variable competitive offers (depending on utilities) they could choose from in June 2012 alone, among a range of suppliers active in each territory to serve residential customers.
- As Table 2 shows, residential customers in nine states had from 3 to 66 different green power competitive offers (depending on utilities) they could choose from in June 2012 alone, among a range of suppliers active in each territory to serve residential customers. These green power options, which competitive suppliers are actively offering, are an important contributor to states meeting their Renewable Energy Portfolio (RPS) standards, discussed more in response to Question 14.

Several restructured markets have developed easily accessible and user-friendly platforms for residential and (and in some cases, small business) customers to compare retail suppliers and their product and service offerings. These are summarized at a high level in Table 1 and 2. Examples include:

- Texas "Power to Choose" - http://www.powertochoose.org
- New York "Power to Choose" - http://www.newyorkpowertochoose.com/
- Pennsylvania "Power Switch" - http://www.papowerswitch.com/
- Illinois "Power 2 Switch" - http://www.pluginillinois.org/
- Connecticut Energy Savings - http://ctenergysavings.com/

Further elaboration of the abundance of service offerings provided by retail choice suppliers is provided in response to Question 2, where Table 3 contains example of retail supplier pricing, products, and services that are available to customers in restructured markets.

Table 1: Residential Fixed and Monthly Variable Competitive Price Offers, by Utility Market (June 2012 - example)

			12-Month Competitive Retailer Fixed Price Offers				Monthly Variable Competitive Retailer Price Offers			
State	Utility	Utility Price to Compare	High c/kWh	Low c/kWh	# of Offers	# of Retailers	High c/kWh	Low c/kWh	# of Offers	# of Retailers
CT	CL&P	7.62	9.99	7.49	*5*	*5*	11.49	6.98	*11*	*11*
CT	UI	7.70	9.99	7.49	*5*	*5*	10.99	6.98	*13*	*12*
DC	PEPCO DC*	9.24	9.59	8.45	*5*	*5*	8.59	7.79	*3*	*3*
IL	Ameren Zone I	4.67	7.50	4.47	*12*	*10*	6.20	4.10	*2*	*2*
IL	Ameren Zone II	4.66	7.50	4.47	*10*	*8*	6.20	4.10	*2*	*2*
IL	Ameren Zone III	4.68	7.50	4.47	*12*	*10*	6.20	4.10	*2*	*2*
IL	ComEd	5.11	7.90	0.06	*17*	*16*	7.60	4.10	*7*	*7*
MD	BGE*	9.73	10.40	8.15	*11*	*11*	8.68	7.99	*3*	*3*
MD	Delmarva MD*	9.15	9.49	8.30	*5*	*5*	-	-	*0*	*0*
MD	PEPCO MD*	9.29	10.70	8.35	*9*	*8*	11.10	7.99	*3*	*3*
MD	Potomac Edison*	5.72	6.45	5.79	*5*	*3*	-	-	*0*	*0*
NJ	PSEG	10.97	14.72	12.49	*4*	*2*	15.89	15.39	*3*	*1*
NJ	JCPL	10.22	12.60	10.79	*6*	*4*	14.25	13.75	*3*	*1*
NJ	Atlantic City Electric	9.79	13.00	11.49	*4*	*2*	14.59	13.75	*3*	*1*
NY	CenHud	6.05	8.60	7.59	*5*	*5*	10.49	5.60	*13*	*10*
NY	ConEd	10.74	12.70	8.90	*18*	*17*	15.99	6.90	*36*	*34*
NY	ConEd Westchester	6.74	10.99	7.46	*18*	*17*	15.99	5.99	*31*	*30*
NY	NiMo	7.78	9.25	6.74	*12*	*12*	11.24	4.90	*20*	*18*
NY	NYSEG	6.42	8.63	6.19	*9*	*9*	10.01	4.23	*18*	*15*
NY	ORU	8.56	10.00	7.50	*11*	*10*	7.50	5.99	*23*	*19*
NY	RGE	6.89	8.27	5.83	*11*	*11*	4.99	0.80	*21*	*19*
OH	AEP	**	7.90	6.34	*6*	*6*	8.34	7.02	*2*	*1*
OH	Dayton	**	6.89	6.40	*3*	*3*	9.75	9.75	*1*	*1*
OH	Duke	**	7.40	5.49	*5*	*5*	9.44	5.49	*11*	*8*
OH	FirstEnergy	**	6.49	5.86	*4*	*4*	5.79	5.79	*1*	*1*
PA	Duquesne Light	6.60	7.90	6.30	*13*	*8*	12.50	6.45	*13*	*11*
PA	MetEd	8.79	9.49	7.49	*14*	*8*	9.49	6.98	*8*	*7*
PA	PECO	8.61	10.49	8.19	*17*	*10*	10.89	7.28	*17*	*8*
PA	Penelec	8.70	8.70	6.69	*8*	*5*	8.99	5.64	*9*	*2*
PA	Penn Power	7.10	6.79	5.79	*2*	*2*	7.29	6.95	*3*	*2*
PA	PPL	8.23	9.29	7.69	*16*	*12*	9.60	6.29	*14*	*13*
PA	West Penn	6.22	7.10	5.33	*9*	*6*	7.99	6.00	*5*	*4*
TX	AEP Central	n/a	8.40	5.10	*53*	*38*	11.94	3.40	*30*	*22*
TX	AEP North	n/a	8.93	5.63	*49*	*35*	11.43	3.53	*26*	*20*
TX	Centerpoint	n/a	8.19	4.99	*55*	*38*	11.23	3.79	*33*	*25*
TX	Oncor	n/a	8.15	5.35	*58*	*41*	11.49	3.55	*31*	*23*
TX	TNMP	n/a	8.07	5.67	*50*	*36*	12.51	4.07	*23*	*19*

Source: State utility commissions (note that TDSP charges are removed for Texas)

* MD utilities' PTC is the weighted average of seasonal variation

**The OH PUCO does not post Price to Compare on their offers website; this information is in EDC tariffs

Table 2: Residential Renewable, Wind or Green Competitive Price Offers by Utility Market (June 2012 - example)

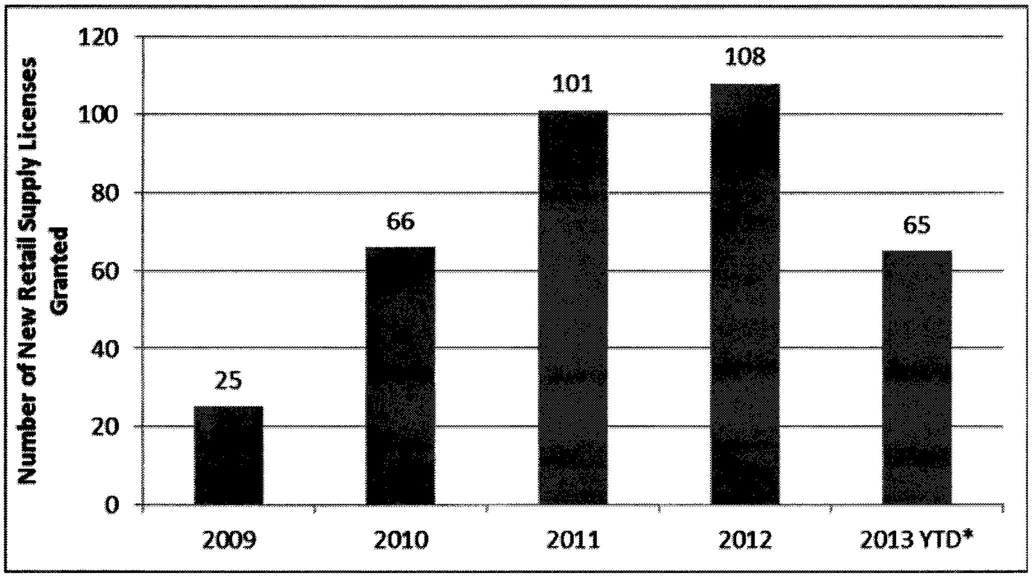
State	Utility	Utility Price to Compare	100% Renewable, Wind or Green Offers High ¢/kWh	Low ¢/kWh	# of Offers	# of Retailers
CT	CL&P	7.62	13.49	7.57	*16*	*9*
CT	UI	7.70	13.49	7.57	*16*	*9*
DC	PEPCO DC*	9.24	10.60	9.40	*8*	*4*
IL	Ameren Zone I	4.67	5.56	4.57	*4*	*2*
IL	Ameren Zone II	4.66	5.56	4.57	*4*	*2*
IL	Ameren Zone III	4.68	6.30	4.57	*4*	*2*
IL	ComEd	5.11	9.80	-	*14*	*7*
MD	BGE*	9.73	12.49	9.18	*17*	*9*
MD	Delmarva MD*	9.15	10.40	9.10	*3*	*2*
MD	PEPCO MD*	9.29	11.99	9.00	*15*	*8*
MD	Potomac Edison*	5.72	8.00	5.89	*3*	*2*
NJ	PSEG	10.97	-	-	*0*	*0*
NJ	JCPL	10.22	-	-	*0*	*0*
NJ	Atlantic City Electric	9.79	-	-	*0*	*0*
NY	CenHud	6.05	9.00	5.85	*6*	*3*
NY	ConEd	10.74	16.50	9.94	*13*	*8*
NY	ConEd Westchester	6.74	12.97	8.49	*15*	*8*
NY	NiMo	7.78	8.94	4.99	*6*	*6*
NY	NYSEG	6.42	8.94	5.72	*7*	*6*
NY	ORU	8.56	11.79	7.73	*10*	*6*
NY	RGE	6.89	7.94	4.99	*5*	*4*
OH	AEP	**	6.79	6.79	*1*	*1*
OH	Dayton	**	8.94	6.70	*2*	*2*
OH	Duke	**	9.44	5.90	*4*	*3*
OH	FirstEnergy	**	6.19	6.19	*1*	*1*
PA	Duquesne Light	6.60	10.40	8.30	*4*	*4*
PA	MetEd	8.79	9.40	8.22	*6*	*6*
PA	PECO	8.61	13.00	-	*22*	*14*
PA	Penelec	8.70	9.49	8.06	*8*	*5*
PA	Penn Power	7.10	7.49	7.39	*2*	*2*
PA	PPL	8.23	11.99	7.94	*23*	*13*
PA	West Penn	6.22	7.79	-	*9*	*6*
TX	AEP Central	n/a	12.94	5.40	*61*	*29*
TX	AEP North	n/a	12.27	6.23	*57*	*26*
TX	Centerpoint	n/a	12.23	5.59	*62*	*30*
TX	Oncor	n/a	12.49	3.85	*66*	*30*
TX	TNMP	n/a	13.51	6.17	*59*	*27*

Source: State utility commissions (note that TDSP charges are removed for Texas)
* MD utilities' PTC is the weighted average of seasonal variation
**The OH PUCO does not post Price to Compare on their offers website; this information is in EDC

Market Entry and Participation of Retail Suppliers

Another important measure of the success of competitive power markets is their ability to attract active retail suppliers to participate in the retail markets. As Figure 1 reflects, the number of licenses granted to retail suppliers entering restructured power markets has grown substantially year-over year since 2009. Even after 15 years of restructuring, many markets are still attracting new retailers to enter and/or enticing existing retailers in other markets to be licensed in additional markets. Participants include some of the largest well capitalized energy corporations from around the world, as well as local entrepreneurs who carve out niche markets in this evolving space.

Figure 1: New Retail Supplier Licenses Granted in Restructured States, 2009 – 2013 YTD



Source: State commission websites reflecting license status. 2013 is through 6/30/13

The growing number of retail suppliers actively entering competitive markets, in addition to benefitting customers in those markets by providing energy choices, services and savings, has an important additional benefit – these new market entries also spur economic development and job creation in restructured markets that would not have existed without competition, such as new call centers. As noted in a recent report on the connection between competitive markets and the economy, "By itself, electric competition cannot rescue a moribund economy. But combined with other policies, electric competition can be a catalyst for economic growth."[11]

Success of Competition in Wholesale Markets: It is also worth noting that restructuring, which began in the 1990s, was undertaken by states that recognized that the vertically integrated/cost-based regulation model was failing to control costs. Thus, the goal of policymakers at the inception of competition was to ensure affordable and reliable electricity for consumers by establishing competitive market principals and constructs to

[11] Attachment A: Ref #A13, "Electricity Competition at Work: The Link Between Competitive Electricity Markets, Job Creation, and Economic Growth"

ensure reliability at the lowest possible costs. That objective remains consistent today. As it does elsewhere in the economy, competition keeps costs as low as possible, drives innovation, and results in product innovations that customers are seeking. Of course, this does not mean that competition promises ever-decreasing prices. Electricity prices, like the prices of all other commodities, are subject to changing market conditions, in some cases global markets, that affect the cost of inputs. This is just as true for traditional vertically-integrated utilities. The competitive market structure ensures that prices remain as low as possible.

Cost-of-service ratemaking employed in the traditional vertically integrated utility model leads to rates that are based on whatever costs are deemed "prudently" incurred, plus an administratively determined profit margin. Cost-of-service ratemaking does not, and will not, provide utilities with the economic incentive to innovate and improve operational efficiencies the way that competition doesbecause the discipline that competitive market forces bring to such spending is lost.[12] That restructuring has been successful in bringing down wholesale costs is clear – in states where restructuring has occurred, power plants are operating at higher capacity factors, and the massive cost overruns for power plant construction of the type seen in Southeast regions have not occurred. In fact, plant operators in restructured states reduced labor and non-fuel expenses, holding output constant, by 3 – 5% relative to other investor-owned utility plants in non-restructured states, and by 6 – 12% relative to government- and cooperatively-owned plants that were largely insulated from restructuring incentives.[13] The beneficiaries of these new efficiencies have been the formerly captive customers of the utilities who had no other supply choice.

The Outlook for Retail Choice Savings in Arizona: There is evidence to suggest that Arizonans in all customer classes will indeed experience savings under retail choice. That evidence comes from the Alternative Generation Service tariff ("AG-1") that was approved by the Commission as part of the settlement of APS's last rate case, and is a service that is available to 200 MW of large commercial and industrial load in the APS service territory. AG-1 allows those customers to find a competitive third party supplier, negotiate pricing for electricity supply, and have that supply delivered to APS for re-delivery to the customer. Virtually all the load eligible for this service subscribed to it. In fact, there was more demand for participation than the capped tariff allowed, such that 141 MWs of load that qualified for the service was not allowed to take service due to the cap placed on program participation. The reason these customers wanted this service was to take advantage of savings that could be achieved through market purchases. Simply put, there is already unfulfilled demand by customers served under monopoly tariffs for lower prices, not to mention a desire for a range of other customized products and services for electricity only available from the competitive market.

12 Attachment A: Ref# A6, "Myths & Realities of Competitive Electricity Markets"

13 Attachment A: Ref #A28, "Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on US Electric Generation Efficiency" and Ref #A36, "Putting Competition Power Markets to the Test - The Benefits of Competition in America's Electric Grid: Cost-Savings and Operating Efficiencies"

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

Response: Most importantly, customers will see myriad benefits from retail choice, including but not limited to new product designs, innovation, additional market participants, customized and value added services – just to name a few, as described further below.

1) *Flexible Terms:* Competitive retail markets provide customers of all types and classes the ability to select or fashion contract terms that suit their preferences. For example, some customers may want a fixed price, while others may prefer some mix of fixed and variable pricing, while others may want daily or hourly pricing. In various customer choice jurisdictions, competitive suppliers offer a range of time periods for pricing and work with customers to extend contract time periods based on their individual value perspective. This flexibility allows customers to manage their energy costs at their own discretion – an individual customer-centric focus that simply is not possible under utility cost-of-service ratemaking. Under cost-of-service rate-making, rate changes are the result of utility filings, the timing and outcomes of which are based on complex proceedings, and sometimes prolonged and opaque settlement negotiations.

2) *Price Signals:* Competitive markets provide efficient price signals in response to changes in the market conditions that drive supply and demand, including changes in fuel prices and general economic conditions.

3) *Price Transparency:* Customers in competitive markets are in a better position to discern and understand the prices of various product and service elements that are most important to them than are customers in traditional contexts in which all customers are presumed to have homogenous needs that can be met with bundled, undifferentiated pricing. Unbundled pricing in competitive markets in which generation/supply, transmission and distribution as well as other elements of each, are priced separately, permits customers to understand the costs associated with electricity service and to make informed choices about individual service packages.

4) *Innovation in energy options and services:* Price may be the primary reason for some, but certainly is not the only reason for switching to a competitive supplier. Customers of all classes are actively selecting competitive green power options, and a range of energy efficiency and load reduction products and services from retail suppliers in competitive markets. Table 2 (in response to Question 1) shows the active green power competitive offers to residential customers in nine restructured markets, in June 2012. In summary, the Attachment A compendium of literature included with these comments presents evidence that demonstrates the benefits of retail choice to residential, commercial, and industrial customers. Retail competition allows residential and business customers in competitive markets to manage and control costs, usage, and other key factors important to each individual customer – in new and powerful ways, using the latest information and technology.

Customers in restructured markets receive competitive pricing, expertise to help them decide the best times to purchase, and a full range of products to choose from.

To provide further specificity with respect to the types of choices that customers will have when retail choice is reopened in Arizona, the retail competitive suppliers who are members of the Retail Competition Advocates and RESA have prepared an overview of the depth and breadth of competitive product service offerings that they offer to both residential and commercial/industrial customers, which are summarized in the Table 3 that follows. These product and services include multiple pricing options, demand response and energy efficiency solutions, renewable energy, financial services to facilitate the deployment of renewable installations, net metering services, value added products and services, and multiple payment options. Customers can make choices based on these types of retail offerings that are as simple as (i) a fixed price offer that guarantees them savings, compared with what they would have paid with their utility, (ii) a more time-based price, or (iii) opt to select from a number of renewable, energy efficiency, or other value-added products and services.

Table 3: Examples of Competitive Retail Supplier Products and Services

Category	Product / Service Type	Product / Service Examples, Features
Core Products	**Fixed Price Solutions** - Gives customers one fixed price per kWh throughout their contract term	• Price certainty – one fixed price for all usage • Simplicity – make a one-time decision and get an easy-to-understand bill • Easy budget management – manage to the budget because the price is fixed in advance for all usage • Usage variance protection – keep a fixed price even when usage varies from events beyond the customer's control, such as a long summer heat wave
	Variable Price Solutions - Gives customers a month-to-month price per kWh with no contract or cancellation fee	• Flexibility – great option for customers looking for a no-contract plan • Optionality – customers enjoy a month-to-month rate and have the freedom to switch to a fixed price plan at any time • Simplicity – customer can cancel or change the contract at any time with no fee
	Time Based Solutions - Gives customers a month-to-month price per kWh or fixed term that rewards customers for shifting their usage from peak to off-peak periods.	• Hourly Rate Plan - offers different rates during on-peak and off-peak hours throughout the day, encouraging customers to use energy when costs are lower
	Prepaid Electricity – Allows customers to pay for a specific amount of electricity to activate an account and customer continues to pay as often as they like to their account balance above zero	• No deposit nor credit check required • Customers can cancel or change the contract at any time with no fee • Customers receive text messages or emails that allow them to see how much electricity they are using on a regular basis allowing them to better manage energy usage and costs
Optional Product Offerings *Examples of additional services brought to the market by*	**Renewable Energy** - Green-e Energy Certified Renewable Energy Certificates (RECs) from wind power to meet customer's environmental and budget objectives	• Support the operation and development of renewable power plants • Product zero emissions of greenhouse gases and no harmful pollutants • Promote sustainable energy programs in the U.S.
	Demand Response Technologies - provides a way for companies to respond to energy market and	• Streamlines processes to improve the efficiency of the customer's business

Category	Product / Service Type	Product / Service Examples, Features
competitive suppliers that can be utilized by customers at their discretion	demand changes	• Capacity offer: Participant would provide an agreed upon reduction to a specified base line for a not to exceed number of instances and time duration per instance. • Economic offer: Participant would reduce load in response to a notification. Response would be optional and benefits would accrue only to those customers that respond. This program can be offered to all customer classes. Payments could vary by event or for simplicity be set for all events. • Customized offer: Participant could define their own program incorporating elements from the standard offers.
	Solar Power – an important and fast-growing part of the nation's energy supply	• Clean technology – a great option for those seeking an alternative to fossil fuel technologies • Sustainable – if a customer's organization is seeking to develop sustainable and responsible strategies, solar and other green technologies can help • Solar expertise – capabilities to design, install and maintain customers' solar projects
	Energy Efficiency - energy services to maximize efficiency, minimize costs and reduce emissions	• Technical Solutions – including retrofits and upgrades, facility modernization, and on-site generation from renewable sources • Conservations programs – Direct Energy can help create conservation programs for customer's organizations. • Heating, Ventilation and Air Conditioning support (including maintenance or upgrade programs) • Electrical (including home energy management, electric vehicle plug-in stations) • Plumbing (including solar thermal & tankless water heaters)

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

<u>Response</u>: Experience from existing competitive retail electricity markets demonstrates that the pace and completeness with which competitive benefits flow to all customer classes are largely a function of the timing and policies implemented by regulators on key components necessary to support retail competition, including the manner in which customers make the transition to retail choice (e.g., whether through the use of a Provider of Last Resort ("POLR")[14] service or some other mechanism, and customer education. The following sections discuss these issues in more detail.

Retail Service Transition Considerations: Even with the depth and breadth of experience on the implementation of retail choice at all customer class levels, Retail Competition Advocates and RESA fully support the principle that special care must be taken to ensure customers are able to choose a competitive supplier, while ensuring that they also have continued availability to reliable service, as Arizona transitions to a fully competitive retail market.

The mechanism by which Arizonans will make the transition to a customer choice environment, the form and structure of POLR service, and related considerations, are key decisions that will be made in the Phase 2 of this proceeding. Specifically, Phase 2 of this investigation should give careful consideration to whether (and if so, for how long) utilities retain either the ability or obligation to provide POLR service. If the utilities retain such an ability or obligation, it will be essential to establish a clear transition period toward a fully competitive retail market where the utilities responsibilities relate solely to transmission and distribution services. Most importantly, determining the best solution for the customers should always be at the forefront of these decisions. It is not about what is most comfortable or easy for the utility or any other market participant, this analysis is about what is best for customers and to allow the full benefits of retail competition to be afforded to Arizona consumers.

Regardless of the transitional or final design eventually chosen by the Commission, it must be a pre-requisite that any provision of POLR service by the utility, if deemed necessary for any limited period of time, does not create any unfair competitive advantage that would undermine the long term success of customer choice. All jurisdictions that have retail competition have addressed the question of what transitional mechanism to use to move customers from a vertically-integrated utility model to one in which all customers actively consider their electricity supply choices. Attachment A to this filing contains reports that provide a comprehensive review of the various models used in other states for the Commission and Staff's review to provide a

[14] Provider of Last Resort ("POLR") is a term that is often used interchangeably with "default service." Competitive markets require provisional services in the limited instances where either a retail supplier exits the market or, if applicable, an entity (utility or otherwise) serves customers that have not independently selected a competitive provider. While market designs differ on whether these two services are linked or provided by the same entity, for purposes of these comments, the term POLR service is used to describe both these provisional services.

framework for the discussion of this critical topic in Phase 2 of this proceeding. These specific issues and cites are discussed more fully in the response to Questions 4 and 11.

Customer Education Outreach: Educating consumers about retail competition is crucial to a successful transition to competitive markets. There are three important factors regarding consumer education programs: funding, hosting, and timing. Education efforts should be led by state regulatory authorities that consumers view as objective parties, and supplemented by stakeholder groups. Table 4, presented in response to Question 4, summarizes the initial statewide customer education expenditures and initiatives of eleven restructured states.

Texas and Pennsylvania are two examples of states that have undertaken the imperative objective of proactive and on-going customer education regarding retail electric competition. For example, the Texas Public Utility Commission continues to educate consumers through its Power to Choose Website more than a decade after retail completion was implemented there.[15] The website provides information about the retail electric market, the shopping process, retail offer comparisons and reasons to consider choosing a competitive supplier. Leading up to the transition period in Texas numerous channels, entities, and messages were used to fully inform and educate customers in an unbiased fashion as to the upcoming market changes prior to any changes occurring. This was one of many astute policy designs implemented to ensure, from day one, the retail market was a success.

Pennsylvania has a similar customer education website hosted by the state's Public Utility Commission to serve as a resource for customers to understand their options.[16] In addition, the Pennsylvania commission directed its electric utility companies to send commission-endorsed postcards encouraging customers to shop and directing them to the website,[17] and its commissioners have actively promoted shopping in their speeches throughout the state. Stakeholder working groups are also effective in consumer education efforts because stakeholders have first-hand knowledge of the market, and can identify gaps in consumer knowledge and effective strategies for reaching out to consumers. The Pennsylvania commission convened such a group to develop a consumer education campaign in connection with its investigation into retail markets.[18]

Other Considerations: In addition to the determinations about customer education outreach, and what role, if any, the utility will have in provision of POLR service, the following are important considerations that should also be evaluated in Phase 2 of this proceeding:

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[15] http://www.powertochoose.org/

[16] http://www.papowerswitch.com/

[17] *Investigation of Pennsylvania's Retail Electric Market: Intermediate Work Plan*, Docket I-2011-2237952, Final Order, at p. 7 (March 1, 2012)

[18] *Investigation of Pennsylvania's Retail Electric Market: Intermediate Work Plan*, Docket I-2011-2237952, Final Order, at p. 12 (March 1, 2012)

- Customer protection issues
- Issues surrounding access to customer information (how, when, and what customer information is available to suppliers and the process for customers to opt out if they choose to do so)
- Permissibility of municipal aggregation programs (i.e., California, Illinois, New Jersey, Massachusetts, and Ohio) and the opportunities customers may have as a result of successful programs such as these
- Purchase of Receivables (either the utility's purchase of supplier receivables or vice versa, depending on the customer's billing arrangement)
- Supplier Consolidated Billing to constantly reaffirm the relationship between the customer and their supplier as well as minimize transaction costs
- Metering issues related to data access, data security, meter data management, and ownership

Implications for Arizona: The options for market design to achieve the optimal savings and services for customers can and should be examined in Phase 2 of this proceeding to investigate more specific implementation options and leverage lessons learned from other markets to support Arizona's optimal retail market design. Retail Competitive Advocates and RESA believe, given the lessons learned in other jurisdictions, there does not appear to be any need to impose restrictions on retail choice for any customer class, or to require a lengthy transition that slowly expands retail choice to progressively smaller customer classes.

Finally, the fact that several retail business license applications remain pending before the Commission demonstrates that competitive retail suppliers stand ready to enter the Arizona market equipped with marketing expertise and technical know-how required for the operation of a vigorous and dynamic marketplace for all customer classes.

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?**

Response: While it is important to consider competitive market risks to customers, it is equally important to acknowledge the risks presently being borne by customers who have no choice but to remain in an outdated and unnecessary monopoly market structure. Some of these risks are: 1) distorted electricity prices 2) tariff rigidity, (3) lack of customization to fit individual customer needs and preferences, such as fixed contractual periods at known prices, increased levels of renewable energy, and the ability to manage their families' and businesses' energy budgets and (4) risks borne by consumers with utility generation investment. These risks are just as real as any risks that retail competition presents, and Retail Competitive Advocates and RESA respectfully request that the Commission recognize and appreciate this important point as they read these comments.

With respect to retail competition, the risks have historically been unfairly characterized in two general categories: (1) if a retail supplier goes out of business, that supplier's customers will not have access to electricity; and (2) retail competition is just a "zero-sum" game, in which cost savings enjoyed by large commercial and industrial customers will come at the expense of small commercial and residential customers. These are archaic myths that have that have been proven as such in markets with successful retail market structures, where in fact these "competitive market risks" discussed above have been addressed, as follows.

Lack of Access to Electricity Supply. Retail Competitive Advocates and RESA note here, as they have noted in the response to Question 3 and 11, that Phase 2 is the proper place to focus on the particulars of POLR service design with respect to what happens when a competitive supplier goes out of business.

Nevertheless, by way of example, Texas has designed its competitive retail market to allow retail suppliers to thrive in their specialized areas so customers always benefit from having competitors offer services. The utility is able to focus solely on its core competencies of transmission, distribution and reliability services and the utilities play no role in the provision of POLR service. Indeed, the regulated utilities in Texas offer no retail electricity supply services at all. Instead, competitive suppliers with the ability to innovate and design multiple product offerings provide a wide range of products and services to customers. By designing a system that allows the utility to focus on its wires specialty and allows retail suppliers to focus on their specialty of creating and providing energy supply products and services has created the "win-win" outcome for customers in Texas.

Other states have chosen to implement a POLR service that is available to any customers who makes no affirmative choice to take service from a competitive supplier in the period immediately following the opening of the market. In these models, the POLR service, for whatever time period it is deemed necessary, is provided by the utility, although it can also be provided by a competitive supplier.[19] To ensure that POLR service does not undermine retail choice, the pricing of that service must be based on prevailing market prices, which is achieved through wholesale auction processes. In markets where POLR service remains in place beyond an initial transition period, the frequency and manner in which these auctions are held and the pricing of POLR serivce is re-set becomes a linchpin to success of retail competition.[20]

The Zero-Sum Game Fallacy. Some opponents of retail choice assert that retail competition is a zero-sum game, in which all of the cost-savings are captured by large commercial and industrial customers and paid for through higher prices charged to residential and small commercial customers. In addition, some utilities have argued that reductions in the amount of electricity sold to their retail customers means they will have to recoup costs from the remaining POLR service customers – primarily residential and

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[19] While many jurisdictions have chosen to allow the regulated utility to provide POLR service, in two states (Pennsylvania and Massachusetts) the utility commission has the statutory ability to designate a non-utility POLR service provider.

[20] Attachment A: Ref #A23, "Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices"

small commercial ones, resulting in a "last man standing" situation, in which a few customers are responsible for paying millions of dollars of utility costs.

This fear has no basis in fact, for several reasons. First, utilities who do not sell electricity to their retail customers can sell that electricity in the wholesale market. Second, the entire point of competition is to encourage greater operating efficiencies. For example, utilities can purchase electricity in the wholesale market whenever the costs are lower than their own generating resources. Third, utility stranded generation costs are dealt with separately. Once those costs have been fairly recovered from all retail customers – shoppers and non-shoppers alike – recovery of the utilities' fixed generation costs takes place in the competitive market.

Arizona specifics: The manner in which Arizona will address each of these issues regarding the transition to a competitive retail market will impact the level of benefits that customers achieve in the retail market. Moreover, the mechanisms adopted to ensure separation of the utility generation function from their transmission and distribution function, as discussed in the response to Question 7, will also play a significant role in determining what type of POLR service will be best in Arizona.

Fortunately, Arizona has significant experience upon which to draw. In the late 1990's this Commission tackled electric restructuring head on. With the help of Staff, incumbent utilities, electric industry groups, and competitive retail suppliers, a framework for the transition to retail competition was developed. In Decision No. 61973 (October 6, 1999)[21] and Decision No. 62103 (November 30, 1999)[22] respectively, the Commission approved settlement agreements for Arizona Public Service ("APS") and Tucson Electric Power ("TEP") which provided for rate reductions for residential and business customers; set forth the amount, method and recovery of stranded costs that APS and TEP could collect in customer charges; established unbundled rates; and provided that APS and TEP would separate their generating facilities, which would operate in a competitive market apart from their its transmission and distribution systems, which would continue to be regulated.[23]

In addition, Decision Nos. 61973 and 62103, and the respective settlement agreements attached thereto described in detail the benefits to customers, competitive retail suppliers, and the incumbent utilities as follows: allowing competition to commence in APS's and TEP's service territories months before otherwise possible;

[21] Decision No. 61973 was a consolidation of Docket Nos. E-01345A-98-0473 In the Matter of the Application of Arizona Public Service Company for Approval of Its Plan for Stranded Cost Recovery; E-01345A-97-0773 In the Matter of the Filing of Arizona Public Service Company of Unbundled Tariffs Pursuant to A.A.C.R. 14-2-1601 et seq.; and RE-00000C-94-0165 In the Matter of Competition in the Provision of Electric Services Throughout the State of Arizona

[22] Decision No. 62103 was a consolidation of docket Nos. E-01933A-98-0471 In the Matter of the Application of Tucson Electric Power Company for Approval of Its Plan for Stranded Cost Recovery; E-01933A-974-0772 In the Matter of the Filing of Tucson Electric Power Company of Unbundled Tariffs Pursuant To A.A.C.R. 14-2-1601 et seq.; and RE-00000C-94-0165 In the Matter of Competition in the Provision of Electric Services Throughout the State of Arizona

[23] *See*, Decision No. 61973 at 4; *see also* Decision No. 62103 at 4

establishing both Standard Offer and Direct Access rates, and providing for annual rate reductions with a cumulative total of as much as $475 million by 2004 for APS and a rate reduction of 1% on July 1, 1999 and another 1% on July 1, 2000 for TEP; ensuring stability and certainty for both bundled and unbundled rates; resolving the issues of APS's and TEP's stranded costs and regulatory asset recovery in a fair and equitable manner; providing for the divestiture of generation and competitive services by APS and TEP in a cost-effective manner; removing the specter of years of litigation and appeals involving APS, TEP and the Commission over competition-related issues; continuing support for a regional independent system operator ("ISO") and the Arizona Independent Scheduling Administrator Association ("AZISA"); continuing support for low income programs; and requiring APS and TEP to file interim codes of conduct to address affiliate relationships.[24] Under the terms of the settlement agreements, APS was authorized to recover stranded costs in the amount of $350 million dollars[25] and TEP was authorized to recover stranded costs in the amount of approximately $683 million through 2008(through both a fixed competition transition charge ("CTC") and a floating CTC).[26]

The transition to retail competition in Arizona is by no means a novel exercise. Arizona has been down this road before. This Commission, with the help of all interested parties, has examined many of the issues raised in this proceeding in great detail more than 10 years ago. The Retail Competition Advocates and RESA are confident that the Commission and interested parties can again come together to update the good work done previously with both information related to the experiences with restructuring in other jurisdictions and new information that relates to conditions on the ground in Arizona today and thereby develop a framework that allows this important transition to once again move forward and expeditiously begin delivering real benefits to customers.

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

Response: To the extent that this question is asking how the Commission can prevent market structure abuses and/or market manipulation by competitive retail suppliers, the Commission's first line of defense is its process for awarding Certificates of Convenience and Necessary ("CC&N") to retail suppliers before they can begin selling energy to retail consumers. The CC&N application and vetting process is already in place and allows the Commission full opportunity to assess the credibility, integrity, and capabilities of every applicant – and to impose specific conditions and safeguards on those applicants as a condition for receiving a CC&N.

Moreover, the AZISA protocols that are expected to govern market operations for the delivery of power to retail choice customers include market monitoring functions which will be active when the retail choice market is reopened. As noted in the response to Question 6, Phase 2 of this proceeding can and should include a review and update of

[24] *See*, Decision No. 61973 at 4; *see also* Decision No. 62103 at 4
[25] *See*, Decision No. 61973 at 17; *see also* Settlement Agreement dated May 14, 1999 at 5
[26] *See*, Decision No. 62103 at 19-20; *see also* Amended Settlement Agreement dated June 9, 1999 at 4-5

the AZISA protocols, as necessary, to assure that appropriate market monitoring functions are in place.

In addition, the Commission will once again have the opportunity to promulgate electric competition rules. As was previously developed through the Electric Competition Rules enacted in the 1990's, the Commission developed rules that described and oversaw: Commencement of Competition; Certificates of Convenience and Necessity; Competitive Phases; Competitive Services; Services Required to be Made Available; Recovery of Stranded Costs; System Benefits Charges; Transmission and Distribution Access; In-State Reciprocity; Rates; Service Quality, Consumer Protection, Safety, and Billing Requirements; Reporting Requirements; Administrative Requirements; Separation of Monopoly and Competitive Services; and Disclosure of Information.[27] In light of the extensive experience over the past decade in states with customer choice, Retail Competition Advocates and RESA regard these existing rules as well designed, and can serve Arizona well as the starting point for ensuring there are comprehensive rules that will facilitate the reopening of retail choice so Arizonans can again benefit from retail electric competition. This review will be a key priority in Phase 2 of this proceeding.

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?**

Response: There are two areas that must be addressed for there to be an effective and efficient market structure for retail electric competition.

Congestion Management: Systems and protocols necessary to allow competitive suppliers to deliver power over the existing transmission and distribution grid to retail customers must be in place. Fortunately, the original development of the AZISA tariff contemplated the need for these types of systems and protocols. In a separate filing, AZISA is providing answers to this and several other questions posed in the Request for Comments that describe the history of AZISA, the FERC-approved tariffs under which it operates, and the protocols that are in place to provide congestion management services upon the resumption of retail choice in Arizona. The Retail Competition Advocates and RESA will continue to work with AZISA to review and update those protocols to ensure that they are consistent with current Western Electricity Coordination Council (WECC) reliability standards, address any other legal and tariff related issues, and work toward appropriate AZISA staffing.

Development of Competitive Market Rules: Market participants must have clarity with respect to the market rules that will apply in the retail choice market. Again, Arizona has been down this path before and in the response to Question 5, Retail Competition Advocates and RESA have noted that the existing Electric Competition Rules are comprehensive and provide a solid foundation for re-initiating this task.

[27] *See*, R14-2-1602- 1616

Toward this end, Retail Competition Advocates and RESA will have a comprehensive set of proposals ready with respect to both stranded costs and recommended modifications to the existing competitive market rules when the Commission makes the decision to move forward to resume retail electric choice in order to facilitate the completion of these tasks expeditiously in Phase 2 of this proceeding.

It is also important to note that upon the resumption of retail choice, the competitive market rules become a "living" document that can and should be re-evaluated periodically for the purpose of incorporating improved practices and adjusting as necessary to market conditions.

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

Response: Retail competition does not require full divestiture by the utilities of their rate regulated assets to either an affiliated or a non-affiliated third party. However, it is important that there be sufficient separation of the generation operations from regulated transmission and distribution operations such that delivery service can be properly priced and untainted by legacy cross-subsidies, and so that there is adequate insulation of decision making to prevent discrimination in access based on generation or supply ownership.

Divestiture of a regulated utility's generating assets to either an affiliated or a non-affiliated third party provides a transparent solution that fully ensures a level competitive playing field and brings immediate transparency to the calculation of stranded costs. Divestiture or sale of generating assets also ensures a level competitive playing field, although it is not as transparent with respect to the stranded cost calculation. These observations are explained more fully in the following sections.

Why Retail Competition Requires Some Form of Corporate Separation: One of the most important factors in regulating an electric utility, regardless of whether there is retail competition, is to ensure that customers who purchase regulated services do not cross-subsidize competitive market activities in which the utilities may engage. Not only are cross-subsidies inequitable – forcing customers to subsidize a utility's services, whose profits are not returned to those customers – they are inefficient. Cross-subsidies can provide a utility with an unfair competitive advantage over other market participants who lack such subsidies. There are two general ways to limit cross-subsidies, both of which involve the creation of firewalls to separate the utility's regulated and competitive market activities: functional separation and structural separation.

Functional Separation: Functional separation is the least-costly, but least effective, form of firewall. Under functional separation, a generation-owning utility's corporate structure remains the same. The utility forms two separate business functions – one for regulated activities (distribution and transmission) and one for unregulated, competitive activities.

The key to functional separation is establishment and *enforcement* of strict accounting guidelines and standards of conduct that govern the business relationship of the regulated versus unregulated businesses. Strict accounting guidelines are necessary to ensure that regulated activities are not allocated costs (which are then paid by utility ratepayers) that should be allocated to competitive market activities. Functional separation also requires utilities to enact codes of conduct between personnel who work on regulated activities and unregulated ones. For example, there must be rules in place that limit information-sharing between personnel who oversee regulated activities and personnel who oversee competitive activities, so as not to provide the personnel with responsibilies in the unregulated business with strategic or other operational information not available to other competitors.

A common method that is used to limit cross-subsidies is *activity based costing*, or ABC, which focuses on allocating indirect costs (e.g., overhead, management fees, etc.) to their proper activities, something that traditional cost accounting does not do. The goal of ABC is to convert indirect costs into the functional equivalent of direct ones and thus reduce the potential for cross-subsidization of competitive activities by regulated ratepayers.

With functional separation, additional regulatory oversight is required to ensure the utility manages "migration risk," that is, the risks of customers leaving utility service. Specifically, regulators should not allow utilities to make generation investments on behalf of customers who shop after functional separation is in place. Otherwise, all ratepayers, those who shop or those on POLR service, may be saddled with unnecessary costs and additional risk. The best way to do this, because it places generation supply risk on suppliers who are best equipped to manage that risk, is through a competitive auction process for POLR service load, rather than drawn out regulatory proceedings to determine whether a utility's generation investments are prudent.

Although functional separation is the simplest administrative form of restructuring, it is the least effective. The problem with functional separation is that no matter how detailed the accounting rules and codes of conduct, there is simply no way to structure those regulations to provide for stringent, ironclad enforcement of the codes of conduct, especially when some personnel will serve management roles with respect to both regulated and unregulated activities.

Structural Separation: Under structural separation, the utility spins off its generating assets into an unregulated affiliate or subsidiary, which is a separate legal entity.

Depending on the generating assets spun off, additional steps are required. Typically, for example, the debt obligations associated with the generating assets also must be transferred or refinanced through the new subsidiary. The ability to do this depends on the assets' market value. Second, the utility must be compensated for the "stranded" costs of its assets, i.e., the aggregate of the assets' total book value less their aggregate total market value. The regulator establishes the overall stranded cost amount and the schedule over which the utility recovers those costs through a non-bypassable rate surcharge. As is the case with function separation discussed, above, it is equally important in the structural separation models to ensure there is no inappropriate sharing of strategic and operational information sharing between the competitive affiliate and the regulated transmission/distribution company. This requires a thorough code of conduct to govern the communications between the two and careful state regulatory oversight.

The need for separating generation from wires assets was driven home in a recent New Hampshire Public Utilities Commission staff report.[28] The report highlights that Public Service Co. of New Hampshire's (PSNH) continued ownership of generation facilities, with the costs imposed on the utility's customer base, is not compatible with the state's now-thriving competitive retail electricity market and will distort good market outcomes for consumers. The staff report underscores the fact that the best interests of New Hampshire electricity consumers will be served if the original intent of the state's 1996 electricity restructuring law is adhered to and PSNH is required to divest itself of its power plants.

Implications for Arizona: In Arizona, the issue of divestiture was fully evaluated when retail choice was first opened in 1999. A.A.C. R14-2-1615(A) and (C) set forth requirements and conditions for Affected Utilities (regulated electric utilities) to divest generation assets and competitive services in anticipation of competition in the state. In *Phelps Dodge Corp. v. Ariz. Elec. Power Coop.,* 207 Ariz. 95, 83 P.3d 573 (App. 2004) ("Phelps Dodge"), the Court deemed the promulgation of A.A.C. R14- 2-1615(A) and (C)[29] went beyond the Commission's plenary ratemaking powers, and without separate statutory authorization, was invalid on its face. However, the court also found that the intended separation of monopoly and competitive services could still be achieved through Affected Utilities' compliance with R14-2-16 15(B), which was not challenged. More specifically, the Court stated:

> *"If the Affected Utilities choose to retain competitive assets for a period beyond the prescribed date, or indefinitely, the competitive market is seemingly unaffected, as long as the Affected Utilities abide by R14-2-1615(B), which prohibits them from competing."* [Phelps Dodge at p. 181].

Hence, it does not appear that there would be a legal or functional need to require divestiture of generation assets by regulated electric utilities to move forward with retail competition.

In summary, while divestiture of assets provides the preferred and cleanest separation of wires and supply, it is not required for a successful retail choice program.

[28] Attachment A: Ref# A4, "Public Service Company of New Hampshire -- Report on Investigation into Market Conditions, Default Service Rate, Generation Ownership and Impacts on the Competitive Electricity Market

[29] A.A.C. R14- 2-1615(C) provided that Electric Distribution Cooperatives were not subject to the provisions of A.A.C. R14- 2-1615 unless it offers competitive electric services outside its distribution service territory

What is required is that incumbent utilities not be allowed to make investments going forward on behalf of retail suppliers and their customers and recover the associated costs through non-bypassable charges, and that safeguards are implemented to ensure a level playing field between utility personnel that manage utility owned assets (whether owned bv the utility or an unregulated affiliate) and the personnel that manage the transmission/distribution operations.

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

Response: There are three categories of costs that must be accounted for in the transition to retail electric competition, as follows:

AZISA related costs: The first category of costs associated with the transition to retail electric competition will be the costs to implement new systems and update the tariffs and protocols by which AZISA will manage scheduling and settlement of power, as outlined in the response to Question 6. A study completed for AZISA by Utility System Efficiencies, Inc. provides a range of estimates of the costs that would be incurred to bring AZISA into full operation; that report is being provided by AZISA in its response to the Request for Comment.

It should be noted that the option exists for the incumbent utilities to formally join or form a FERC regulated RTO or ISO. Althought Retail Competition Advocates and RESA do not believe that membership in and RTO or ISO is essential for the resumption of retail electric choice in Arizona, the benefits of more efficient dispatch across a broader footprint may suggest that such membership is in the interest of Arizona's ratepayers. If the incumbent utilities have an interest in such membership, and regulators approve it, Retail Competition Advocates and RESA would support such a membership.

Utility systems implementation: The second category of costs associated with the transition to retail electric competition will be costs that the utilities will incur to appropriately interface with competitive suppliers on meter data and other customer information data exchanges. Retail Competition Advocates and RESA presume that the utilities will seek recovery of these costs, and do not dispute that they should be afforded such recovery for just and reasonable costs. The precise mechanisms for recovery of these costs can be addressed in Phase 2 of this proceeding.

Customer Education: As noted in the response to Question 3, designing and implementing customer-focused programs to provide education about retail choice are an important part of the transition. Educating the public about the specifics of restructuring is an imperative of the new competitive electric markets. Statewide consumer education programs exist in all restructured states. Utilities in those states are required to fund the campaigns and in return receive cost recovery through various methods. About half of the electric restructured states required mandatory utility territory-specific consumer education campaigns as part of their initial restructuring plans, with education efforts undertaken by all utilities to some degree, whether it includes bill inserts, direct mail, media relations, or outreach to community-based organizations. Determining the content, layout and other key components of a successful customer education campaign can be discussed in Phase 2.

Table 4: Initial Statewide Restructuring Customer Education Expenditures

State	Initial Program Duration (years)	Total Budget (Millions)	Total $ per IOU customers
California	1	89.3	$8.89
Connecticut	2	8.7	$6.06
Maine	2	1.5	$2.16
Massachusetts	2	2.0	$0.81
Maryland	2	5.6	$2.82
Michigan	4	26.8	$6.71
New Hampshire	2.5	2.2	$4.05
New Jersey	3	39	$11.02
Ohio	5	31	$6.87
Pennsylvania	4	98	$20.31
Texas	4	34	$5.44

Source: KEMA Retail Customer Education Study, 2000

Note: Customer education initiatives have extended in most markets past these initial mandates

9. Will retail electric competition impact reliability? Why or why not?

Response: At the outset, it is important to note that there is no evidence to support any contention that retail electric competition results in any compromise of system reliability. In fact, with respect to one critical aspect of reliability – the reliability of the sub-transmission level distribution system – there is and should be no impact to reliability as a result of allowing retail suppliers to directly deliver power to customers on the utility distribution system, and no customer should be put at a disadvantage with respect to distribution level service as a result of being on competitive supply.

Beyond issues related to distribution system reliability, there are two aspects to reliability management within the electric sector that must be considered as part of the transition to retail choice: transmission and distribution grid reliability and resource adequacy, which are discussed in more detail below.

Transmission Grid Reliability: The first is managing the reliability of the transmission grid. This is virtually the same whether or not there is retail competition, as the issues associated with ensuring that there is adequate voltage and frequency regulation, operating reserves, and management of imbalances, all of which must be managed continuously in real time, do not change when retail choice is introduced. Specialized systems and technologies to monitor and respond to real time fluctuations in electricity consumption and the dispatch of regulation and operating reserves to keep the system balanced are overseen by the North American Electric Reliability Corporation (NERC). NERC is a not-for-profit entity whose mission is to ensure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces reliability standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC, in turn, has been certified (since 2006) by FERC as the designated Electric Reliability Organization (ERO), pursuant to Section 215 of the Federal Power Act.

The ERO has delegated oversight and enforcement authority to eight different Regional Reliability Coordinators responsible for various regions of the United States, one of which is the Western Electric Coordinating Council ("WECC"). Arizona's transmission system falls with the WECC reliability footprint.

The reliability standards enforced by NERC through the EROs will not change as a result of retail competition, and therefore reliability at the transmission level will be unaffected by retail competition.

Resource Adequacy: The second area of reliability that must be discussed is that of maintaining an adequate supply resource base, i.e., sufficient capacity, to meet expected load and established planning reserve margins. This is an area that will affect retail electric competition, as competitive suppliers will and should be expected to meet established resource adequacy reliability requirements, including maintenance of an acceptable planning reserve margin of capacity, and appropriate levels of operating reserves. Such obligations are the norm in all retail choice states where there are capacity market constructs, and Arizona need be no different.

In fact, data from retail choice jurisdictions in the northeast show that there has been a substantial growth in available generating capacity since the introduction of retail competitive choice as well as the operation of regional transmission organizations. The contention by some, most recently by opponents of customer choice in Michigan, that retail choice discourages investment in new generation, and that generation resource reliability may be undermined by customer choice, is belied by the facts. Pertinent data come from the PJM Interconnection, the nation's largest regional transmission organization in the northeast, as well as the one in which the great majority of utility service territories allow retail customer choice.

- PJM's Summer 2013 resource assessment shows an estimated 26.7% reserve margin relative to the calculated 16% requirement [30]
- PJM's most recent capacity auction attracted a total of 169,160 MW, including an all-time high of 5,463 MW in new capacity and imports of 7,843 MW[31]
- PJM reported on June 20, 2013 commitments of 2,353 MW of economic, price responsive demand response resources[32]

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?

Response: With the resumption of retail electric choice in Arizona, mechanisms will need to be put in place that allow competitive retail suppliers to deliver power to their retail customers. These issues are discussed in the response to Question 6. Other

[30] http://www.pjm.com/~/media/planning/res-adeq/res-reports/20130619-forecasted-reserve-margin-mw-new-gen.ashx)
[31] http://www.pjm.com/~/media/about-pjm/newsroom/2013-releases/20130524-pjm-capacity-auction.ashx
[32] http://www.pjm.com/~/media/markets-ops/dsr/2013-dsr-activity-report-20130610.ashx

than these changes to power scheduling and congestion management protocols, the incumbent utilities will continue to own and operate the their transmission system, and are already required to do so consistent with WECC and NERC reliability standards, and subject to FERC regulations with respect to regional transmission planning, as discussed in the response to Question 9. Therefore, Retail Competitive Advocates and RESA do not envision significant issues that need to be addressed as part of the transition to retail electric competition, but welcome the opportunity in Phase 2 of this proceeding to confirm this.

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?

Response: The design of each state's retail market directly determines the competitive activity that will result in that market, and especially impacts: whether or not competitive suppliers enter a market and the degree to which those competitive entities launch multiple price offers and services. In turn, competitive offers and services drive customer engagement, interest, and participation in making choices afforded them in restructured markets. Competitive activities, operate in a feedback loop with regulatory supervision. Increasing supplier and customer activity in some restructured markets has prompted a re-examination of retail rates and policies, as well as a refinement of POLR pricing and marketing rules. This continuous interaction among market participants and the regulatory authorities has resulted in a vast body of "lessons learned" from market experiences in other restructured states, summarized below and addressed more thoroughly in the cited reports provided in Attachment A.[33]

Although there are different models that have been used in different jurisdictions, the most successful models share several key characteristics

- Transparency. For retail competition to succeed, all participants must understand the basic market structure and the rules going forward. In this regard, transparency means limiting the ability of any participant – whether competitive supplier, or the incumbent utility, – to secure an unfair competitive advantage. For example, structural separation of utility generating assets into a completely separate generating company is more transparent than simply separating generation functionally within the utility, as discussed in the response to Question 7. Transparency also means establishing tariffs that identify the different costs, including those that are bypassable and non-bypassable, for all utility ratepayers.
- Regulatory Certainty. Investors dislike uncertainty, because uncertainty increases costs. Regulatory uncertainty presents particular difficulty, because unlike price or other market risks, there are no tools to hedge it.

[33] Attachment A: Ref#A9, "Annual Baseline Assessment of Choice in Canada and the United States"; Ref #A31, "State Competitive Procurement: A Partial Survey of Best Practices"; Ref # A39, "A Comprehensive View of U.S. Electric Restructuring With Policy Options for the Future"

As a result, if regulators constantly change the structure of retail competition, they drive away new investment and participation by competitive suppliers. Regulatory certainty means letting competitive markets work as intended, so as to attract new investment and market participation. It also means resisting actions that may provide short-term expediency at the expense of long-term market viability.

- Maximize Customer Participation. Competition should not be limited to select groups of customers, but open to all customers. Just as there would be no reason to not allow residential customers to select their long-distance telephone service provider, there is no reason to prevent residential electric customers from selecting a competitive retail service provider. Moreover, active participation by as many customers as possible – including residential customers – in making choices about their electricity supply should be a key criterion in judging a market's success. The responsiveness of customer demand to accurate price signals is a critical benefit of a competitive market not only at the retail level but also at the wholesale level, where the cumulative impact of customer choice can be the lowest cost alternative for what would otherwise be expensive upgrades or additions to the generation and transmission infrastructure.

- Short Transition Period. It may be impossible to implement full retail competition and restructuring "instantly." For example, a utility may be unable to spin-off generating assets into a competitive generation affiliate immediately because of the need to refinance existing debt obligations. Similarly, what role, if any the utility may have in the provision of POLR service, will need to be carefully examined. Nevertheless, the transition to full market competition should be made as quickly as possible to ensure customers begin experiencing the benefits of full retail competition as expeditiously as possible. It is important to note that accomplishing the transition as quickly as possible not only eliminates market inefficiencies, but also serves to eliminate any financial market concerns about how the changes will impact the utilities from a credit ratings perspective.

While the above represent key elements for successful retail choice implementation, the successful retail choice markets that exist in many jurisdictions are not identical; each has unique features that were developed in response to particular concerns and preferences of regulators and market participants in those jurisdictions. Arizona, too, grappled with all of the details of retail choice when it developed its retail choice program back in 1998, sorting through all the issues associated with launching a successful retail choice program, and developing a robust base from which to craft a comprehensive framework for re-establishing retail electric competition in Arizona. Nevertheless, Retail Competition Advocates and RESA recognize that over ten years have passed since the original Competition Rules were put in place, and that they will need careful review and updating to make them operational, but this task can be readily accomplished in Phase 2 of this proceeding.

In terms of whether any particular model should be avoided, Retail Competition Advocates and RESA urge the Commission to remain mindful that the underlying premise for industry restructuring and retail choice is that robust competition for electricity supply will create more cost effective and innovative outcomes for customers than rate regulation. Moreover, incumbent utilities' core functions related to transmission and distribution would remain fully regulated. In order for competitive supply markets to thrive and bring the competitive pressures that lower prices and spur innovation, any model that perpetuates rate-regulated ownership of supply side assets will undermine the achievement of those fundamental goals, and therefore should be avoided.

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

Response: Retail Competition Advocates and RESA addressed this issue in their response to Questions 1 and 2 and therefore ask that those responses also be considered as part of this response. Specifically, the compendium of reports provided in Attachment A provide detailed information on how retail choice has impacted retail rates in states that have retail choice. An example of the type of data included in Attachment A, and one of the most compelling pieces of recent data that is responsive to this question come from an analysis of data from the U.S. Energy Information Administration and the Bureau of Labor Statistics. This data shows that between 1997 and 2012, inflation-adjusted retail rates in states with restructured competitive retail markets decreased by 4% while those in states that rely on monopolies increased 7%. And retail customers in all classes have enjoyed these decreases. Specifically, inflation-adjusted rates for residential, commercial, and industrial customers in retail choice states decreased by 6.5%, 12.1%, and 1.7%, respectively, over this period while rates in these same customer classes in monopoly utility states increased by 3.9%, 1.2% and 10.1%, respectively.[34]

Fundamental to an appreciation of the impact of competition on rates is the recognition that with retail choice, customers can contract for terms and conditions that best suit their needs. Customers are not held to a specific rate design, in contrast to the more rigid tariffs that exist under traditional regulation (See Table 3 in response to Question 2, which provides examples of competitive retailer products and services). Further, and of great importance, customers can contract for prices for extended periods and for known periods of time into the future. These can be multi-year in duration. In contrast, rates under traditional regulation are rarely guaranteed for any set period of time (except to the extent that there is a fairly certain procedural schedule) that start if and when the utility filing for new rates choose for the clock to start ticking.

Along with the ability of customers to choose pricing terms and conditions, customers have the ability to work with suppliers to modify such contractual arrangements when/if they decide it is appropriate to do so. This flexibility customers have in a competitive market – to continually re-examine ther pricing and product

[34] Attachment A: Ref # A2, "States with Restructured Electricity Markets Post Lowest Rates of Change"

solutions that are best suited for them – is precisely what customers are denied under traditional regulation.

13. Is retail electric competition 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 implementation of retail electric competition?

Response: Yes, retail competition in Arizona remains viable despite the Phelps Dodge decision. In fact, the Phelps Dodge decision does not affect the Commission's authority to move forward towards to re-establish a plan to implement electric competition, and as such rules authorizing such implementation are still in effect. Specifically, A.R.S. section 40-202(B) declares that "it is the public policy of this state that a competitive market shall exist in the sale of electric generation service," and it "confirms" a wide range of powers of the Commission to accomplish the "transition to competition for electric generation service." Such powers include the authority of the Commission to "establish reasonable requirements for certificating and regulating electricity suppliers that are public service corporations." [A.R.S. section 40-202(B)(2)] It is important to note in this regard that A.R.S. section 40- 202(B)(2) does not presume to prescribe the nature or extent of such requirements as may be necessary, in order to accomplish the transition to competition. Rather, that is left to the discretion of the Commission, subject to its compliance with applicable Arizona law.

The sole Electric Competition Rule[35], which was held by the Phelps Dodge decision to be facially invalid, is not indispensable to the ability of the Commission to effectively oversee and regulate retail electric competition. More specifically, with reference to R14-2-1611(A) [Rates], the Court found that any Commission review and approval of Electric Service Provider rates and charges must comply with the Commission's responsibilities under Article 15, Section 3 and Article 15, Section 14 of the Arizona Constitution. Hence, there is no rule which could legally define in advance, and in the absence of evidence, what constitutes a "just and reasonable" rate or charge, which is what R14- 2-1611(A) had attempted to do. However, the Phelps Dodge decision also specifically found that R14-2-1611(A) could be severed from the remainder of the Electric Competition Rules with regard to the issue of whether the rules were incompatible with the Commission's constitutional responsibilities under the Article 15, Section 3 and Article 15, Section 14.

> *". . .we have no difficulty concluding that the rules are independent of R14-2- 1611(A) and are enforceable standing alone."*

[Phelps Dodge at p. 151]

The two (2) Electric Competition Rules, which were held by Phelps Dodge to be invalid because the Commission's promulgation thereof exceeded its authority, also are not essential to the ability of the Commission to effectively oversee and regulate retail

[35] A.A.C. R14-2-1601 through 1616

electric competition. More specifically, with reference to R14-2-1609(C)-(J) [Transmission and Distribution Access], Phelps Dodge held that this rule invaded the managerial prerogative of Affected Utilities to decide how best to open access to their transmission and distribution facilities, in the absence of constitutional or legislative authority for the Commission to do so. [Phelps Dodge at p. 171]. However, interim developments in the electric utility industry in Arizona pertaining to the AZISA, as well as a related Commission decision, suggest that the Phelps Dodge decision does not preclude AZISA from continuing to perform an important role in relation to retail electric competition. In this regard, in Decision No. 68485, the Commission stated:

> *"We find that Phelps Dodge had no impact on the continuing economic viability of the AISA, and that it does not reduce the continued public benefit associated with maintaining Commission support of the AISA at its current level of operations. The AISA currently provides the important public benefit of keeping the possibility of retail access available in Arizona to consumers at a minimal cost, by providing potential competitors with the necessary assurance that they will have fair and equitable access to transmission until an RTO is formed and approved by FERC to take over that function."* [Decision No. 68485, page 15, lines 5-11].

With reference to R14-2-1615(A) and (C) [Separation of Monopoly and Competitive Services], Phelps Dodge found subsections (A) and (C) were beyond the Commission's plenary ratemaking powers, and without separate statutory authorization, were invalid. However, as described above, the Court found that the intended separation of monopoly and competitive services could still be achieved through Affected Utilities' compliance with R14-2-1615(B), which was not challenged.

The Electric Competition Rules, which were invalidated by the Phelps Dodge decision because they were not submitted to the Arizona Attorney General for Certification under the Arizona Administrative Procedure Act ("APA"), also are not indispensable to the ability of the Commission to effectively oversee and regulate retail electric competition, as the following discussion indicates:

> a. R14-2-1603 [Certificates of Convenience and Necessity]: Given the language of A.R.S. section 40-202(B) and A.R.S. section 40-281(A), the Commission has authority under A.R.S. section 40-281(A) to grant ESP CC&Ns on a case-by-case basis.
>
> b. R14-2-1605 [Competitive Services]: The CC&N required for an ESP in order to provide competitive retail electric service, which was required under R14-2-1605, can be obtained pursuant to the Commission's authority under A.R.S. section 40-281(A)].
>
> c. R14-2-1609 [Transmission and Distribution Access]: As to subsections(C)-(J), the previous observations regarding the same are equally applicable in this context. As to subsections (A) and (B) of R14-2-1609, The Commission has the

power to impose these requirements as a part of its overall constitutional and statutory authority to regulate electric public service corporations, without the necessity of promulgating specific regulations.

d. R14-2-1610 [In-State Reciprocity]: While the provisions of these regulations are desirable from the perspective of providing for a complete "level playing" field on which retail electric competition could occur, the reality is that the entities which would be subject to the requirements of these particular provisions are few and their potential impact upon retail electric competition in Arizona would be slight, if not non-existent.

e. R14-2-1612 [Service Quality, Consumer Protection, Safety and Billing Requirements]: These provisions are important to an effective regulatory scheme. However, if the Commission resumes retail electric competition at this time <u>on a case-by-case basis</u>, it could include the relevant provisions from this portion of the Electric Competition Rules as conditions or requirements within its decision granting an ESP CC&N. Alternatively, the Commission could condition the effectiveness of such ESP CC&N upon its receipt of the requisite Arizona Attorney General Certification, which the Commission would promptly undertake to obtain.

f. R14-2-1614 [Administrative Requirements] These provisions to the Electric Competition Rules would contribute to and enhance the overall contemplated regulatory scheme. However, the absence of such provisions would not be fatal to the effective functioning of that regulatory scheme. Moreover, most, if not all, of the actions of the Commission contemplated by these provisions fall within the scope of the Commission's broad regulatory authority under the Arizona Constitution and statutes, and thus do not require these particular provisions as a legal predicate for the Commission to act.

g. R14-2-1617 [Disclosure of Information] The observations made above with regard to R14-2-1612 are equally applicable to this portion of the Electric Competition Rules.

The Commission can validate those Electric Competition Rules, invalidated by the <u>Phelps Dodge</u> decision for failure to obtain that Arizona Attorney General Certification required by the APA, by promptly submitting the same (or a modified version) to the Arizona Attorney General and requesting the requisite certification.

In addition, the <u>Phelps Dodge</u> decision can be used as an effective tool as it provides specific guidance to the Commission as to what it must do and what it may consider, incident to the establishment of rates and charges for an Electric Service Provider for the provision of competitive retail electric service. More specifically, with regard to "fair value" rate base [Article 15, Section 141, the court indicated that:

1. The Commission has an affirmative duty to determine "fair value" rate base;
2. The Commission must consider "fair value" rate base in setting rates;
3. The Commission may consider "other information" in setting rates;
4. While the Commission cannot ignore "fair value," it is not required to set rates based on "fair value" rate base in a competitive market.

Furthermore, with regard to "just and reasonable" rates [Article 15, Section 31, the court noted that:

1. The Commission is required to determine and set rates which are "just and reasonable":
   a. The Commission cannot let market forces alone set such rates; but,
   b. The Commission can consider market forces in setting such rates;
2. The Commission has a duty to discover and remedy potential overreaching and abuse by public service corporations, including Electric Service Providers;
3. The Commission also has a duty to be sure that rates are fair to public service corporations, including Electric Service Providers;
4. When the Commission looks solely to market forces to set rates, it also violates its constitutional duty to consider "fair value" rate base;
5. The Commission may authorize competitive market forces to set rates within an authorized range of rates, as long as that range has been established in a manner that satisfies the "just and reasonable" requirement.

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

Response: Retail Competition Advocates and RESA fully expect that competitive retail suppliers will be accountable for meeting Arizona's Renewable Energy Standard ("REST"), currently set at 15% by 2025. In Phase 2 of this proceeding, Retail Competition Advocates and RESA will submit their specific modifications to the competitive market rules to incorporate such accountability. Indeed, the ability for competitive retail suppliers to offer renewable energy options that go beyond mandated levels is one of the most prevalent value added service that retail suppliers offer to their customers who have specific personal or corporate goals to achieve lower carbon footprints.

In the fifteen restructured states that have an RPS mandate that requires competitive retail suppliers to comply with the state's RPS, the burden to meet the RPS mandate does not just fall on the investor owned utility – the retailers are an important part of the state's overall plan to meet the RPS requirements.[36] Moreover, as described in Table 2 (response to Question 1 - an example of green pricing products for residential customers which retailers are offering in nine states in of June 2013) and in Table 3 (response to Question 2), retail suppliers are actively offering renewable products and services that contribute to the overall renewables objectives established in restructured markets and requested and pursued by end use customers.

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

Response: efficiency standards establish specific, long-term targets for energy usage reductions that utilities or non-utility program administrators must meet through customer energy efficiency programs. An energy efficiency standard is similar in concept to REST; while REST requires that electric utilities generate a certain percentage of electricity from renewable sources, an energy efficiency standard requires that they achieve a percentage reduction in energy sales from energy efficiency measures. Twenty-four states have fully-funded policies in place that establish energy efficiency targets and programs. Of those states, sixteen are restructured and allow retail customer choice.[37]

Developing the program infrastructure and implementing energy efficiency programs, irrespective of the restructuring status of a state, has traditionally been the domain of investor owned utilities. However, with retail competition, consumers become much more educated about electricity pricing, and therefore energy efficiency emerges naturally as consumers look for ways to modify their energy usage to better manage their energy costs. Indeed, energy efficiency services are an important value-added product offering of competitive suppliers, as demonstrated in the response to Question 2, Table 3.

The Commission's review of the Competitive Market Rules that will need to be addressed in Phase 2 should explore the role that competitive suppliers can and will play in supporting the statewide objectives for energy efficiency reductions.

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

[37] U.S. Energy Information Administration (EIA), as of April 2013: http://www.eia.gov/todayinenergy/detail.cfm?id=12051

[37] U.S. Energy Information Administration (EIA), as of April 2013: http://www.eia.gov/todayinenergy/detail.cfm?id=12051

Response: Retail Competition Advocates and RESA recognize that the Commission and stakeholders are in the midst of carefully evaluating and potentially modifying existing net metering policies and regulations to (i) reflect concerns about the impact of potentially excessive and unnecessary net metering subsidies, (ii) determine what type of charges distributed generation customers should pay for the transmission and distribution services they continue to receive, especially with respect to residential service, and (iii) address the recovery of stranded utility generation costs that are created by deployment of distributed generation. These are important issues, and are under consideration in several other states as well - as utilities, their customers, and policy makers begin to see the fundamental impacts that the widespread deployment of distributed generation has on how the distribution system functions, and the extent to which there need to be fundamental changes to residential rate designs to ensure that solar customers who continue to use the distribution system are paying the appropriate share of the costs.

Retail Competition Advocates and RESA will closely monitor the net metering proceeding that is ongoing, and will be prepared to assist the Commission and staff with any questions that arise with respect to the role that retail choice can and should have in addressing the important issues associated with net metering.

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

Response: Customers who participate in retail choice do so for a wide variety of reasons. Some are searching for the lowest possible price, some want price certainty, others want to use on-site resources, some want to access a greener and cleaner supply. In short, they are looking for customized levels of customer service that simply are not available in the vertically integrated model. In order to provide this broad range of service, retail electric service suppliers engage in extensive portfolio planning, and risk management, consistent with the reliability and environmental goals of the policymakers in the retail choice jurisdiction. As noted throughout these comments, Retail Competition Advocates and RESA fully expect to be required to meet clearly stated reliability and environmental requirements, as is the case in retail choice jurisdictions throughout the country.

The impact retail electric competition will have on utility resource planning depends on whether or not the utilities divest their supply side resources, and the extent to which they retain a POLR obligation. If they divest their supply assets and have no POLR obligation, their planning process will be focused solely on their transmission and distribution systems.

The issues associated with utility planning and procurement in the event they divest generation assets, but retain a POLR obligation, are discussed in the response to Questions 7 and 11, as are the issues associated with utility planning and procurement in the event they do not divest.

Retail Competition Advocates and RESA emphasize that a market design which allows the utilties to retain ownership of supply side assets, costs would continue to be recovered on a regulated cost-of-service basis. However, this approach will undermine the achievement of the fundamental goals of moving to a competitive retail market, and thus this structure should be avoided.

18. How will retail electric competition affect public power utilities, cooperatives and federal controlled transmission systems?

Response: The Arizona Legislature provided a blueprint for the enactment and regulation of retail electric competition in Arizona by setting up rules to integrate and regulate public service corporations, over which the Commission has jurisdiction, and public power utilities, over which the Commission does not exert jurisdiction.

First, the legislature proclaimed that it is public policy in Arizona that a competitive market shall exist in the sale of electric generation services and provided the Commission with significant authority to implement retail electric competition. (*See*, A.R.S. § 40-202(B)). In addition, the Legislature determined that public power entities[38] may participate in retail electric competition statewide and shall open their entire service territories to competition to electricity suppliers certificated by the Commission pursuant to A.R.S. § 40-207 and to providers of other services. (See, A.R.S. § 30-803(A)). Furthermore, the Legislature provided public power entities with the authority to determine the terms and conditions for such electric competition[39] and required that public power entities and the Commission coordinate their efforts in the transition to competition in electric generation services in order to promote consistent statewide application of their respective rules, procedures and orders. (*See,* A.R.S. § 30-802(A)). A.R.S. § 30-801, et seq. also provides pricing guidelines,[40] consumer protection rules, outreach and education,[41] confidentiality provisions[42], and rehearing and appellate procedures[43]. Importantly, no Arizona public power entities ever opened their jurisdictions to competition, nor are they required to do.

While it is the case that Arizona's public power, cooperative, and federally regulated entities have the discretion as to whether or not to reopen their jurisdictions to retail choice, Retail Competitive Advocates and RESA note that to the extent competitive retail markets produce greater efficiency, customer degrees of freedom and satisfaction,

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[38] Public power entities are defined as: any municipal corporation, city, town or other political subdivision that is organized under state law, that generates, transmits, distributes or otherwise provides electricity and that is not a public service corporation. (*See*, A.R.S §30-801 (16)

[39] For example, A.R.S. § 30-803(B) requires public power entities to maintain their existing service territories for electric distribution services and prohibits them from providing electric distribution services in service territories of other electric distribution utilities in this state. A.R.S. § 30-803(C) allows electric distribution utilities to continue to provide billing and collection services, metering and meter reading services on a competitive basis for all retail electric customers that have competitive electric generation services

[40] A.R.S. § 30-805

[41] A.R.S. § 30-806, A.R.S. § 30-807, A.R.S § 30-809

[42] A.R.S. § 30-808

[43] A.R.S. § 30-810 through A.R.S. § 30-812

as well as innovation in products and services, those utility enterprises insulated from any direct requirements for customer choice may find pressure to improve their operations and customer relations and service, and indeed even to provide to their ratepayers the retail choice alternatives available to their neighbors. That is, they will need to adapt.

As for the transmission systems owned and operated by the public power, cooperatives, and federally regulated entities, retail competition may accelerate changes already underway in managing growth in the number of market participants and price unbundling and transparency. Transmission owners and operators across the country have greater technical capability than ever to manage utilization of their systems. Operators such as PJM and MISO have demonstrated that they have been able to manage a large number of transmission customers.

III.

CONCLUSION

The overarching conclusions about customer choice compared to traditional monopoly arrangements in the United States retail power markets are:

- Customers of all classes have adapted quickly to opportunities to choose among suppliers and products with terms, conditions and contract periods to match their individual preferences.
- No price advantage can be attributed to traditional tariff setting under rate-of-return regulation compared to market-based pricing under which customers can shop for price and contract terms, conditions and periods.
- Delivery reliability, reserve margins, fuel mix, diversity of supply, and achieving environmental goals are at least as good in retail competition models as under traditional vertical monopoly regulation; no problems in these areas that have been attributed to customer choice and competition by authoritative government or independent industry reviewers.
- Examination of existing customer choice models shows that retail choice can be made available to all classes of ratepayers along with POLR service, as necessary for customers who have not chosen an alternative supplier, and that the necessary separation within the utilities of the generation and transmission functions can be achieved fairly.

Competition yields the best results for consumers. Of this, there is widespread, mainstream acceptance in the United States and much of the world today. How Arizona moves from an unnecessary regulated monopoly model to a market-based system with all of the accompanying benefits for retail electric customers is the real question at hand.

Time is of the essence. There is no reason, save for the protection of the monopoly *status quo*, for Arizona consumers to be denied access to the innovation in technology and services presently being enjoyed by electric retail customers in many other states.

We urge the Members of the Arizona Corporation Commission to implement customer choice in electric service by moving this proceeding to Phase 2 as quickly as possible so that Arizonans can begin to reap the multitude benefits that only retail electric choice can deliver.

Dated this 15th day of July 2013.

Respectfully submitted,

Lawrence V. Robertson, Jr.
Robert J. Metli
Attorneys for Noble Americas Energy Solutions LLC, Direct Energy LLC, Constellation NewEnergy, Inc.

for

Melissa Lauderdale, President
Retail Energy Supply Association

The original and thirteen (13) copies of the foregoing Comments will be mailed for filing this 15th day of July 2013 to:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

A copy of the foregoing Comments will be emailed or mailed this 15th day of July 2013 to:

All Parties of Record

Attachment A
Compendium of Retail Choice Literature

The reports in this table with an asterisk (*) in the Ref# field are those which are specifically cited as footnotes throughout these comments; others are included because of their relevance to this investigation and are intended to provide the Commission and Staff with additional insights and data on retail electric choice.

Ref #	Title	Author	Date	Summary	Link
* A1	Regulation & Relevancy: Assessing the Impact of Electricity Customer Choice	John L. Domagalski and Philip R. O'Connor	2013	The burden of proof is shifting to monopoly states to justify why not competitive markets. This analysis compares competitive vs. traditionally regulated states with regard to electricity prices, savings, and customer benefits.	http://www.competecoalition.com/files/O'Connor-Domagalski%20-1-17-13.pdf
* A2	States with Restructured Electricity Markets Post Lowest Rates of Change	COMPETE Coalition	2013	An assessment of historical residential, commercial, and industrial electricity rate changes, leveraging EIA's annual price data.	http://www.competecoalition.com/files/EIA%20restructured%20states%20data%20chart%20March%202013%20update.pdf
A3	Investigation of Pennsylvania's Retail Electricity Market: End State of Default Service	Pennsylvania Public Utility Commission	2013	After 15 years with a competitive retail power market, the PA PUC investigation (and this order) examines the model to further the development and aid in the maturation of a healthy and competitive retail electric market in Pennsylvania.	http://www.puc.state.pa.us/pcdocs/1214105.docx
* A4	Public Service Company of New Hampshire -- Report on Investigation into Market Conditions, Default Service Rate, Generation Ownership and Impacts on the Competitive Electricity Market	Staff of the New Hampshire Public Utilities Commission and The Liberty Consulting Group	2013		http://www.puc.state.nh.us/Electric/IR%2013-020%20PSNH%20Report%20-%20Final.pdf
A5	Engaging and Enrolling Low Income Consumers in Demand Side Management	DEFG	2013	This paper explores different approaches to engaging and enrolling low income consumers in DSM programs. These are the 1) Outreach	http://defgllc.com/publication/engaging-and-enrolling-low-income-consumers-in-demand-side-

Ref #	Title	Author	Date	Summary	Link
	Programs			Approach, 2) Behavioral Approach, 3) Partnership Approach, and 4) Transactional Approach.	management-programs/
* A6	"Myths & Realities of Competitive Electricity Markets"	Electric Power Supply Association (EPSA)	2013	An fact-based refutation of several key myths about the benefits and efficacy of competitive retail markets.	http://www.epsa.org/industry/index.cfm?fa=mythsRealities
* A7	Retail Electric Competition in Michigan: Growing Michigan's Economic Garden	Dr. Jonathan Lesser, Continental Economics, Inc.	2012	A report showing that increasing electric competition in MI would lower electric costs for businesses and consumers, stimulating economic growth and creating thousands of new jobs for Michigan residents.	http://www.ecnstudy.com/Retail_Electric_Competition_in_Michigan_-_Final.pdf
* A8	Retail Electric Choice: Proven, Growing, Sustainable	Dr. Philip O'Connor	2012	A report examining the surge and sustainability of electric choice in restructured markets.	http://www.competecoalition.com/files/COMPETE_Coalition_2012_Report.pdf
* A9	Annual Baseline Assessment of Choice in Canada and the United States	Distributed Energy Financial Group LLC	2012	The 2012 assessment and scorecard tracking progress in restructured electricity markets.	http://www.competecoalition.com/files/ABACCUS-2012.pdf
* A10	Retail Electricity Customers Benefit When Suppliers Compete to Serve Them	COMPETE Coalition	2012	COMPETE Coalition blog announcing successful results of several states competitive electricity auctions.	http://www.competecoalition.com/blog/2011/12/retail-electricity-customers-benefit-when-suppliers-compete-serve-them
A11	Duke Energy auction leads to lower electric prices in 2012	Ohio Public Utilities Commission	2012	Ohio Public Utilities Commission Press Release announcing successful result of competitive electricity auctions lower customer prices.	http://www.puco.ohio.gov/puco/index.cfm/media-room/media-releases/duke-energy-auction-leads-to-lower-electric-prices-in-2012/
A12	Office of Retail Market Development: Annual Report	Illinois Commerce Commission	2012	Assessment of retail choice in Illinois.	http://www.icc.illinois.gov/downloads/public/2012%20ORMD%20Section%2020-110%20report.pdf
* A13	Electricity Competition at Work: The Link Between Competitive Electricity Markets, Job Creation, and Economic Growth	Dr. Jonathan Lesser, Continental Economics, Inc.	2011	A report demonstrating the connection between retail electricity competition and increased economic growth and job creation.	http://www.competecoalition.com/files/COMPETE%20Electricity%20Competition%209.22.11.pdf
* A14	Innovation in Competitive Electricity Markets	COMPETE Coalition, KEMA	2011	A paper exploring the link between competitive electricity markets and the	http://www.competecoalition.com/files/KEMA%20Innovation%20in%

Ref #	Title	Author	Date	Summary	Link
				creation and acceleration of innovation in electricity service offerings and practices, such as demand response and energy storage technologies.	20Electricity%20Markets%20White%20Paper.pdf
A15	Retail Competition in Texas: A Success Story	Barry Smitherman, PUCT Chairman	2011	Presentation made by then PUCT Chairman Barry Smitherman to the PAPUC in its Investigation of Pennsylvania's Retail Electricity Market.	http://www.puc.state.pa.us/electric/PDF/RetailMI/EnBanc060811-P-PUCTX_Opening.pdf
A16	Customer Choice in Electricity Markets: From Novel to Normal	Dr. Philip O'Connor	2010	A paper exploring the status and benefits of retail choice in restructured states.	http://www.competecoalition.com/files/Customer-Choice-In-Electricity-Markets_0.pdf
A17	Analysis Of Standard Offer Service Approaches For Mass Market Customers	The Northbridge Group	2010	Testimony submitted before the Rhode Island Public Utilities Commission by National Grid presenting the Northbridge Group's comprehensive analysis of utility electricity procurement for default service customers.	http://www.ripuc.org/eventsactions/docket/4041-NGrid-Compliance(1-22-10).pdf
A18	Restructuring Key to Cheaper Cleaner Electricity	John Kelly (Galvin Electricity Initiative)	2010	Article identifying the often overlooked environmental benefits of restructuring electricity markets.	http://www.coalpowermag.com/commentary/Restructuring-Key-to-Cheaper-Cleaner-Electricity_290.html
A19	Allocating Investment Risk in Today's Uncertain Electric Industry: A Guide to Competition and Regulatory Policy During "Interesting Times"	Analysis Group	2009	A paper making the case for competitive electricity markets to stay the course through the economic crisis.	http://www.epsa.org/documents/Tierney_-_EPSA_-_Allocating_Investment_Risk_-_September_2009_FINAL.pdf
A20	Competitive Electricity Markets: The Benefits for Customers and the Environment	National Economic Research Associates, Inc. (NERA)	2008	An analysis showing the benefits of electric restructuring and case for maintaining through long transition periods.	http://www.nera.com/67_5309.htm
A21	Facilitating Wind Development: the Importance of Electric Industry Structure	National Renewable Energy Laboratory (NREL)	2008	Analysis demonstrating retail competition is beneficial for development of renewables.	http://www.competecoalition.com/files/Renewables%20Revised%20--%20Renewables%20DR%20Innovation.pdf
A22	Innovation in Retail Electricity Markets: The	National Economic Research Associates,	2008	Retail markets are providing benefits to consumers in the form of new products and	http://www.competecoalition.com/files/Innovation%20in%20the%20R

Ref #	Title	Author	Date	Summary	Link
	Overlooked Benefit	Inc. (NERA)		services and innovative methods of providing service	etail%20Electric%20Market%20Exec%20Summary.pdf
* A23	Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices	Tierney and Schatzki (Analysis Group)	2008	An analysis of various policies and practices for utility procurements.	http://www.naruc.org/Publications/NARUC%20Competitive%20Procurement%20Final.pdf
A24	State Competitive Procurement: Model Success Stories and Lessons Learned	Electric Power Supply Association (EPSA) and Dickstein Shapiro Law Firm	2008	A paper highlighting case studies from competitive procurement regulations, orders and Requests for Proposals ("RFPs") in competitive power markets, grouped into "model success stories" and "lessons learned stories."	http://www.epsa.org/forms/uploadFiles/B8660000000C.filename.EPSA_Competitive_Procurement_Case_Studies_4-08.pdf
A25	Embrace Electric Competition or It's Déjà Vu All Over Again	The Northbridge Group	2008	An analysis identifying the flaws in electricity regulation and benefits of competition.	http://www.hks.harvard.edu/hepg/Papers/Embrace_Electric_Competition_Or_Its_Deja_Vu_All_Over_Again.pdf
A26	Texas Retail Electric Competition: Impact on Residential Prices 1995 - 2008	Intelometry, Inc	2008	A study concluding that retail competition applied downward pressure on residential prices in Texas' competitive retail electric market.	http://www.thefreelibrary.com/Study+Concludes+Retail+Competition+Has+Applied+Downward+Pressure+On...-a0189947003
A27	ERCOT Texas's Competitive Power Experience: A View from the Outside Looking In	Analysis Group Susan F. Tierney,	2008	Taking a vantage point in mid-2008 and from outside of the state, this paper examines Texas's electricity market from two lenses: qualitatively, by looking at structural features and quantitatively, by tracking performance using a range of numbers and metrics.	http://www.analysisgroup.com/uploadedFiles/Publishing/Articles/Tierney_ERCOT_Texas_study_11-08.pdf
* A28	Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on US Electric Generation Efficiency	Kira R. Fabrizio (Emory University), Nancy L. Rose (MIT Dept. of Economics) and Catherine D. Wolfram (Haas School of Business, UC Berkeley)	2007	A paper showing the impact electric restructuring had on reducing labor and non-fuel expenses relative to investor-owned and government-owned plants.	http://faculty.haas.berkeley.edu/wolfram/Papers/FRW_AER_0607.pdf
A29	The Benefits of Electric	Dr. Jonathan Lesser	2007	An analysis of the benefits to Pennsylvania	http://www.epga.org/PAWhitePape

Ref #	Title	Author	Date	Summary	Link
	Restructuring to Pennsylvania Consumers			from electric restructuring.	rJAL11082007.pdf
A30	Retail Electric Competition in New York: Benefits for the Present, Promise for the Future	Capitol Hill Research Center	2007	An analysis of the benefits to New York from electric restructuring.	http://www.strategic-energy.com/docs/New%20York%20Benefits.pdf
* A31	State Competitive Procurement: A Partial Survey of Best Practices	Dickstein Shapiro Law Firm	2007	A preliminary survey – for those states that have not traditionally used a competitive method to meet customers' supply needs – of "best practices" for competitive procurement in the states. Also, a model rule for state competitive procurement practices, based upon the survey results.	http://www.epsa.org/forms/uploadFiles/b5e700000025.filename.EPSA_Competitive_Procurement_Best_Practices_and_Model_Rule.pdf
A32	The Fallacy of High Prices	Energy Strategies Inc	2006	A paper debunking the myth that rising electricity prices was caused by restructuring.	http://www.energystrategiesinc.com/Documents/11012006_HighPrices.pdf
A33	Markets for Power in the United States: An Interim Assessment	Joskow, P. (MIT)	2006	An analysis of the progress made in wholesale and retail competitive electric markets.	http://www2.econ.iastate.edu/tesfatsi/Joskow2006.USAElectRestruct.pdf
A34	A Review of Electricity Industry Restructuring in New England	Polestar Communications & Strategic Analysis	2006	An analysis of the wholesale and retail market design features and experiences with competition in the five New England state competitive power markets.	http://www.hks.harvard.edu/hepg/Papers/NEEA_0906.pdf
A35	Electricity Pricing in Retail Electric Markets in Texas	Public Utility Commission of Texas	2006	Report to the Texas Legislature providing evidence that electricity rates are lower than they would have been if the industry had not restructued	http://interchange.puc.state.tx.us/WebApp/Interchange/application/dbapps/filings/pgControl.asp?TXT_UTILITY_TYPE=A&TXT_CNTRL_NO=32198&TXT_ITEM_MATCH=1&TXT_ITEM_NO=&TXT_N_UTILITY=&TXT_N_FILE_PARTY=&TXT_DOC_TYPE=ALL&TXT_D_FROM=&TXT_D_TO=&TXT_NEW=true
* A36	Putting Competition Power Markets to the Test - The Benefits of Competition in	Global Energy Decisions, LLC	2005	An analysis finding competition has improved the operating efficiency of power plants, resulting in cost savings, fewer re-fueling	http://www.epsa.org/forms/uploadFiles/506A00000029.filename.Final_Report_-_070805.pdf

Ref #	Title	Author	Date	Summary	Link
	America's Electric Grid: Cost-Savings and Operating Efficiencies			outages, and enhanced reliability.	
A37	Proactive Planning and Valuation of Transmission Investments in Restructured Electricity Markets	Enzo Sauma and Shmuel Oren, UC Berkeley	2005	An Evaluation of transmission planning upgrades in vertically integrated vs. restructured markets.	http://www.ieor.berkeley.edu/~oren/pubs/JRE_transmission_planning_Enzo_v8%20(34).pdf
A38	Getting the Best Deal for Electric Utility Customers	Boston Pacific Company	2004	A guidebook to structuring competitive procurements, particularly where ISOs/RTOs are not yet formed.	http://www.epsa.org/documents/industry/merchantPower/Policy_Guide.pdf
* A39	A Comprehensive View of U.S. Electric Restructuring with Policy Options for the Future	National Conference on State Legislatures (NCSL) and The Regulatory Assistance Project	2003	An examination of the early results of restructuring models; the connection to wholesale markets; and policy options to consider going forward.	http://www.hks.harvard.edu/hepg/Papers/BrownSedano.pdf

A1

Regulation & Relevancy: Assessing the Impact of Electricity Customer Choice

The price spread between restructured states and traditionally monopoly-regulated states has narrowed in the three years since 2008 as much as it widened in the six-year period. In-depth analysis will be needed to determine whether traditional regulation provides discernible consumer benefits compared to competitive customer choice.

by John L. Domagalski and Philip R. O'Connor

The June 18, 2012 edition of *ElectricityPolicy.com* featured Dr. Kenneth Rose's views on the relative merits of traditional regulation of monopoly electricity generation supply service and the relatively new alternative of competitive customer choice in power supply.[1]

John Domagalski *is Director, Markets and Products with the retail energy business of Constellation, an Exelon company. He is a graduate in finance from DePaul University of Chicago and holds an MBA from the Northwestern University Kellogg School.* **Philip O'Connor** *is president of PROactive Strategies, Inc. a Chicago public policy consulting firm and served as Chairman of the Illinois Commerce Commission 1983-85. In 1998, Dr. O'Connor established New Energy Ventures Midwest, a pioneer electricity retail company in Illinois and also served during 2007-08 in the US Embassy in Baghdad, as an advisor to the Iraqi Ministry of Electricity. He earned Masters and Doctoral degrees in political science from Northwestern University.*

Dr. Rose's key contribution to the debate is his method of analysis. Dr. Rose reviews a lengthy time period - 1990 through 2011 - and uses weighted average prices for his comparison of electricity rates between monopoly and competitive states.[2]

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[1] Kenneth Rose, *State Retail Electricity Markets: How Are They Performing So Far? Electricity Policy.com*, http://www.electricitypolicy.com/archives/4455-stateretailelectricitymarkets.

[2] Weighted average electricity prices for states are calculated by dividing total statewide electricity revenue reported by the U.S. Energy Information Administration for all providers, including

Dr. Rose compares the weighted average prices of electricity of a group of 14 customer choice jurisdictions against a group of 30 states that have maintained traditional regulation of vertical monopolies.[3] He excludes seven states from the analysis; five that have had fitful and partial approaches to customer choice and also Hawaii and Alaska due to their geographic separation from the lower 48 states.

Dr. Rose concludes that the jurisdictions he classifies as competitively restructured have not closed the electricity price gap with the states he classifies as traditionally regulated. However, averages can conceal as well as reveal. When viewed from a different vantage point and looked at more closely, the same twenty-two years of price data analyzed by Dr. Rose tells a story of success for competitive electricity markets.

Four Missing Questions

In his analysis, Dr. Rose explores whether electric competition accomplished the following objective:

> "A principal motivation for retail access legislation was that states with high electricity prices relative to other states and the national average were hoping to lower their prices."[4]

He concludes that this goal has not been achieved. However, there are four key points that are missing from the discussion.

The *first* is that a primary goal of pioneer electric restructuring states was to address various combinations of major challenges they faced in the mid-1990s that motivated industry restructuring. These included high and rising retail rates, excess generating capacity, costly nuclear projects, PURPA QF contracts and angry and migrating industrial customers. For example, circa 1994, the electric utilities with significant power purchases from non-utility generators (NUGs, PURPA-QFs) were mainly located in California, Connecticut, Maine, Massachusetts, Michigan, New Hampshire, New Jersey, Oklahoma, Pennsylvania, Rhode Island, Texas, and Virginia, nearly all of which later pursued retail competition.[5] The electricity crises of the past are now over in the retail competition states and the related stranded cost issues have been resolved. Lack of continued failure ought to be regarded as success.

municipal and rural cooperative utilities by total kilowatt hours delivered.

[3] The 14 competitive jurisdictions are Connecticut, District of Columbia, Delaware, Illinois, Maine, Massachusetts, Maryland, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island and Texas. Seven states were excluded, Alaska and Hawaii, and five states that have varied histories of recent choice and traditional monopoly regimes, Arizona, California, Michigan, Montana and Virginia. The remaining 30 states were classified as traditionally regulated.

[4] Rose, *supra note 1, at* 2.

[5] U.S. Energy Information Administration, *Financial Impacts of Nonutility Power Purchases on Investor-Owned Electric Utilities*, at 57 (DOE/EIA-0580 June 1994).

The *second* is that while many advocates of customer choice were seeking to blunt ongoing step rate increases, there were opponents of industry restructuring who warned of unregulated, out-of-control increases in supply prices in the absence of traditional rate-of-return regulation of generation. Those concerns proved misplaced.

Within the next several years, competitive supply may well challenge the combined 27% retail market share held by municipal, rural cooperative and federal utilities.

The *third* is that the competitive states are conveying price signals more promptly than the monopoly structured states. The conveyance of price signals to inform customers of supply-demand conditions was a key goal of the earliest advocates of relying on market forces for electricity supply pricing.[6] Dr. Rose notes that residential prices in the competitively restructured states declined by 1.7% between 2008 and 2011 while average residential prices in the traditionally regulated monopoly states increased by 8%.[7] In the several years prior to the economic downturn that commenced in mid-2008, prices in restructured states increased faster than in traditional states as rate freezes ended and fuel prices and demand grew amidst strong economic activity. However, as shown in the tables that follow, the spread between choice states and monopoly states narrowed as much in the three years since 2008 as it grew in the six-year prior period. Others have noted the more rapid increase in rates in traditional states than in jurisdictions participating in competitively restructured wholesale markets.

The *fourth* is the implicit, yet central question of whether traditional regulation of utility monopolies delivers discernible price benefits to customers. If moving from a traditional form of regulation to competitive choice does not negatively impact comparative long-run average electricity prices, then what is the purpose of the elaborate procedures that characterize traditional regulation of monopoly generation supply prices? Is the purpose, as Tevye in *Fiddler on the Roof* might say, "Tradition!"?

The time has come for a more expansive consideration of the nature of competitive electricity models in contrast to the traditional monopoly model. While the average price of electricity is certainly worthy of note, the massive migration of customers to choice in electricity supply is itself an argument that consumers are finding the option attractive for a variety of reasons.

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6 *See, e.g.*, Philip R. O'Connor, Robert G. Bussa and Wayne P. Olson, *Competition, Financial Innovation and Diversification in the Electric Industry*," by PUBL. UTIL. FORT., Feb. 20, 1986. This article was one of the first in a major industry publication advocating a movement to competition in electricity supply and argued that … "A greater reliance on market forces could correct one of the critical deficiencies of traditional regulation – its inherent inability to match end-user prices with the economic cost of production. Standard regulatory practices attempt to achieve 'equilibrium' by using historical costing techniques to price electricity. However, using traditional regulatory practices, supply only appears to match demand. Regulation, by its very nature, over-prices new capacity and underprices old capacity."

7 Rose, supra note 1, at 3-4.

Millions of customers, accounting for nearly one-fifth of all kilowatt hours consumed in the United States, purchase from non-utility suppliers at market prices.[8] Within the next several years, competitive supply may well challenge the combined 27% retail market share held by municipal, rural cooperative and federal utilities.[9] Competitive retail supply already has substantially greater market share than do any of the non-investor utility categories. In the 14 competitive jurisdictions included in the Rose analysis, regulators and policymakers have consistently expanded opportunities for customer choice. Customer choice is now a well-established feature of the national electricity landscape.

The traditional monopoly model has not been accommodating to the sorts of innovative features of competitive markets that are proving attractive to customers. Among these are the ability to contract for prices for specific periods to match business plans, pricing demand response at its true value to the system and fully rewarding least-cost operating practices by producers and customers alike.

The debate over choice is no longer one of whether competitive electricity will be a part of the nation's energy picture. Rather, with a decade of customers embracing choice in more than a dozen states, the burden of proof is gradually shifting to those who advocate for maintenance of the vertically integrated, monopoly utility model.

Long-Run Average Price Levels

Dr. Rose notes, correctly, that many factors contribute to differences in electricity prices across states. General factors – such as weather, local and regional economic structure, generation types and fuel mix, degree of urbanization, disparate environmental rules, taxation, labor costs and role of federally produced power allocations – are important determinants of long-run electricity price levels.

Differences in these factors, whether external or internal to the electricity business, tend to be regional in nature rather than merely following state boundaries. For example, one of the recent developments has been the concentration of renewable portfolio standards (RPS) in the competitive states.[10] As a general matter renewable resources exert upward pressure on electricity prices. It is important in this regard to note that the 14 customer choice jurisdictions identified by Dr. Rose are, with the single exception of Texas and its isolated ERCOT system, clustered entirely in the northeast quadrant of the United States, defined in great

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8 For an examination of the growth in customer choice in the post-2008 period of economic stress, *see* Philip R. O'Connor, Retail Electric Choice: Proven Growing Sustainable, April 2012 (prepared for the COMPETE Coalition) at http://www.competecoalition.com/files/COMPETE_Coalition_2012_Report.pdf.

9 EIA's most recent State Electricity Profiles Report shows that rural cooperatives sold 10.97% of all kilowatt hours, public or municipal utilities sold 14.85% and federal utilities sold 1.16% for a total of 26.98% that http://www.eia.gov/electricity/state/unitedstates/.

10 The May 2011 FERC update map of RPS in the states shows the great weight of such programs to have been implemented in the 14 competitive jurisdictions. See http://www.ferc.gov/market-oversight/othr-mkts/renew/othr-rnw-rps.pdf.

part by the boundaries of the PJM Interconnection.

Table 1: Residential Rate Ratios
Competitive v. Traditional States; Competitive and Traditional States v. US Average

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1990-2000 Average
Competitive v. Traditional	1.30	1.34	1.36	1.38	1.39	1.39	1.39	1.40	1.36	1.32	1.33	1.36
Competitive v. US	1.13	1.15	1.15	1.17	1.17	1.17	1.18	1.18	1.17	1.15	1.15	1.16
Traditional v. US	0.87	0.86	0.85	0.85	0.84	0.84	0.84	0.84	0.86	0.87	0.87	0.85
	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2001-2011 Average**
Competitive v. Traditional	1.32	1.27	1.29	1.29	1.32	1.37	1.39	1.41	1.36	1.35	1.28	1.33
Competitive v. US	1.14	1.11	1.13	1.13	1.15	1.18	1.19	1.20	1.17	1.17	1.13	1.16
Traditional v. US	0.87	0.88	0.87	0.88	0.88	0.86	0.85	0.86	0.86	0.87	0.88	0.87

Table 2: All-Sectors Rate Ratios
Competitive v. Traditional States; Competitive and Traditional States v. US Average

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1990-2000 Average
Competitive v. Traditional	1.28	1.33	1.35	1.37	1.37	1.38	1.38	1.39	1.35	1.32	1.34	1.35
Competitive v. US	1.11	1.12	1.13	1.14	1.14	1.15	1.15	1.16	1.15	1.13	1.14	1.14
Traditional v. US	0.86	0.84	0.83	0.84	0.83	0.83	0.84	0.83	0.85	0.86	0.85	0.84
	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2001-2011 Average**
Competitive v. Traditional	1.35	1.30	1.32	1.32	1.37	1.42	1.44	1.45	1.36	1.35	1.28	1.36
Competitive v. US	1.13	1.10	1.12	1.13	1.16	1.18	1.19	1.21	1.16	1.16	1.11	1.15
Traditional v. US	0.84	0.85	0.85	0.85	0.85	0.83	0.83	0.83	0.85	0.86	0.87	0.85

All of this suggests that the impact of the specific regulatory regime on long-run price levels would be but one factor among many. Ultimately, it will require a carefully developed multivariate regression analysis to sort out which factors explain how much of the variance in electricity prices is linked to the regulatory structure.[11]

Consumer Prices: Standardized Ratio Comparison

The analysis here begins with a replication of Dr. Rose's comparison of residential electricity prices in the competitive and traditional monopoly model states, after which the analysis expands to cover industrial and commercial customers and all-sectors taken together.

Using data from the U.S. Energy Information Administration,[12] Dr. Rose compares the weighted average[13] 1990-2011 price of electricity for residential customers (including

[11] The optimal unit of analysis would be utility service territories rather than states. However, there are considerable obstacles to such an analysis, not the least of which would be the data requirements.

[12] The data used by Dr. Rose and in this analysis are available in Excel spreadsheet form at the US EIA website. Sales and revenue data for 1990-2010 are accessible at http://www.eia.gov/electricity/data/state/ and 2011 data are accessible Table 5.5B and 5.6A at http://www.eia.gov/electricity/monthly/.

[13] Weighted average prices are calculated by dividing the sum of all megawatt hours sold in all states in each regulatory category, traditional monopoly and restructured, by the sum of all electricity sales revenue in each group.

delivery charges, taxes, stranded-cost fees, etc.) between 14 competitive choice jurisdiction states and 30 traditionally regulated states. The United States average rates used by Dr. Rose and in this analysis encompass all 51 jurisdictions, including the 7 states excluded from the competitive and traditional groups being examined.

Dr. Rose illustrates his rate comparison with graphs that, while visually interesting, sometimes require the reader to estimate the precise relationship of rates in the competitive states to those in the traditional states. The analysis here presents relative price information in tables and takes out the impact of inflation by converting the raw cents per kilowatt-hour (¢/kWh) into ratios in order to standardize the data over the 22-year period. This allows for more precise comparison.

Table 1 presents yearly weighted average residential rates in the 14 competitive jurisdictions as ratios to prices in the 30 traditional states. Averages for two 11-year equal length periods 1990-2000 and 2001-2011 are also presented. During the earlier period of 1990-2000 all states in the two groupings shared nearly identical traditional regulatory regimes and the classic monopoly utility model. The latter period of 2001-2011 roughly approximates the period during which the 14 retail jurisdictions have operated in a significant way under the competitive construct.

Table 1 also presents ratios comparing prices in the competitive states and the traditional states with overall United States average prices. **Tables 2, 3 and 4** do the same for all-sectors, commercial customers and industrial users, respectively.

Table 3: Commercial Rate Ratios
Competitive v. Traditional States; Competitive and Traditional States v. US Average

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1990-2000 Average
Competitive v. Traditional	1.29	1.34	1.36	1.37	1.39	1.39	1.40	1.42	1.38	1.35	1.39	1.37
Competitive v. US	1.09	1.11	1.11	1.12	1.12	1.13	1.14	1.16	1.14	1.13	1.14	1.13
Traditional v. US	0.85	0.83	0.82	0.82	0.81	0.81	0.82	0.81	0.83	0.83	0.82	0.82
	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2001-2011 Average**
Competitive v. Traditional	1.43	1.36	1.38	1.36	1.40	1.43	1.46	1.50	1.36	1.35	1.26	1.39
Competitive v. US	1.14	1.09	1.13	1.13	1.16	1.17	1.19	1.22	1.15	1.14	1.10	1.15
Traditional v. US	0.80	0.80	0.82	0.83	0.83	0.82	0.82	0.81	0.84	0.85	0.87	0.83

Table 4: Industrial Rate Ratios
Competitive v. Traditional States; Competitive and Traditional States v. US Average

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1990-2000 Average
Competitive v. Traditional	1.24	1.30	1.31	1.30	1.28	1.25	1.26	1.29	1.25	1.22	1.26	1.27
Competitive v. US	1.08	1.10	1.11	1.12	1.11	1.09	1.10	1.11	1.10	1.08	1.10	1.10
Traditional v. US	0.87	0.85	0.85	0.86	0.87	0.87	0.88	0.86	0.88	0.89	0.87	0.87
	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2001-2011 Average**
Competitive v. Traditional	1.26	1.24	1.28	1.29	1.34	1.39	1.43	1.36	1.32	1.28	1.21	1.31
Competitive v. US	1.07	1.07	1.10	1.12	1.15	1.18	1.20	1.16	1.14	1.12	1.08	1.13
Traditional v. US	0.85	0.86	0.86	0.86	0.85	0.85	0.84	0.86	0.86	0.88	0.89	0.86

During much of the 1990s, the price levels in the group of 14 jurisdictions that would ultimately undertake industry restructuring were rising as a ratio of the price levels in the 30 states classified as traditional by Dr. Rose. Residential ratios increased from 1.30 in 1990 to 1.40 in both 1997. The all-sector ratios rose from 1.28 in 1990 to 1.39 in 1997. Industrial and commercial ratios rose in a similar pattern during this period.

TABLE 5: High and Low State Average Price Ratio v. US Average Price

	Range	1990	2000	2010
Among 14 Competitive States	High	1.43 (NY)	1.65 (NH)	1.77 (CT)
	Low	.90 (OH&DC)	.89 (DE)	.93 (IL&OH)
Among Traditionally Regulated States	High	1.26 (VT)	1.51 (VT)	1.35 (VT)
	Low	.52 (WV)	.61 (ID&KY)	.63 (WY)

Following the enactment of restructuring laws around the turn of the millennium, competitive state price ratios declined until the mid-2000s when natural gas prices and electricity demand rose with a growing economy. Ratios then rapidly declined following the 2008 economic downturn. As can be seen in Table 2 above, the all-sectors ratio of competitive price levels to those in traditional jurisdictions fell from a peak of 1.45 to 1.28, a 13-point drop.

More recently, the dramatic reduction in natural gas prices and slow economic growth have contributed to further reductions in competitive states' ratios to prices in traditional monopoly states. EIA data for the first three quarters of 2012 produce price ratios among the lowest in the 22-year analytical period. Customers take the opportunity to capture the value of competitive choice state prices that on average have fallen an additional 6 ratio points compared to 2001.[14]

Yearly average ratios, of course, cannot capture the range of individual state price levels that go into making up the averages. **Table 5** provides an indication of the heterogeneity of ratios within the competitive and traditional states, showing the individual states with the highest and lowest ratios against the total United States average price in 1990, 2000 and 2010. The high and low ratios fluctuate as do the states occupying the high and low positions.

Case Study: The Industrial Upper Midwest

Beyond the analyses of high-level aggregate data, there are stories at the regional level that can be instructive. Five states of the industrial Upper Midwest - Illinois, Indiana, Michigan, Ohio and Wisconsin present especially interesting venues to consider the possible price impact of differing regulatory regimes.

[14] EIA state-by-state revenue and sales data through September 2012 allow for the calculation of ratios of competitive to traditional states compared to calendar 2011 levels: at 1.22 v. 1.28 for all-sectors, 1.23 v. 1.28 for residential, 1.19 v. 1.26 for commercial and 1.13 v. 1.21 for industrial.

Table 6: All-Sectors Rate Ratios
Upper Midwest States v. US Average

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1990-2000 Average
Illinois	1.14	1.13	1.13	1.12	1.07	1.12	1.12	1.12	1.11	1.05	1.02	1.10
Indiana	0.82	0.79	0.78	0.75	0.76	0.76	0.76	0.77	0.79	0.80	0.76	0.78
Michigan	1.08	1.07	1.06	1.03	1.03	1.02	1.04	1.03	1.05	1.07	1.04	1.05
Ohio	0.90	0.91	0.89	0.90	0.90	0.91	0.92	0.91	0.95	0.96	0.94	0.92
Wisconsin	0.82	0.81	0.80	0.80	0.79	0.78	0.77	0.76	0.81	0.83	0.84	0.80

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2001-2011 Average
Illinois	0.95	0.96	0.92	0.89	0.85	0.79	0.93	0.95	0.92	0.93	0.90	0.91
Indiana	0.73	0.74	0.72	0.73	0.72	0.73	0.71	0.73	0.78	0.78	0.81	0.74
Michigan	0.96	0.99	0.92	0.91	0.89	0.91	0.93	0.92	0.96	1.01	1.04	0.95
Ohio	0.91	0.94	0.91	0.91	0.87	0.87	0.87	0.86	0.92	0.93	0.91	0.90
Wisconsin	0.83	0.87	0.89	0.90	0.92	0.91	0.93	0.92	0.95	1.00	1.02	0.92

These states share any number of important social, economic and energy industry characteristics that underlie electricity prices and often see themselves as intra-regional competitors.

Indiana and Wisconsin have consistently adhered to traditional regulation and maintained vertically integrated electric utilities and have not employed customer choice even for the largest users. Yet, those two states have had decidedly different price experiences while sharing a common regulatory style over the past decade.

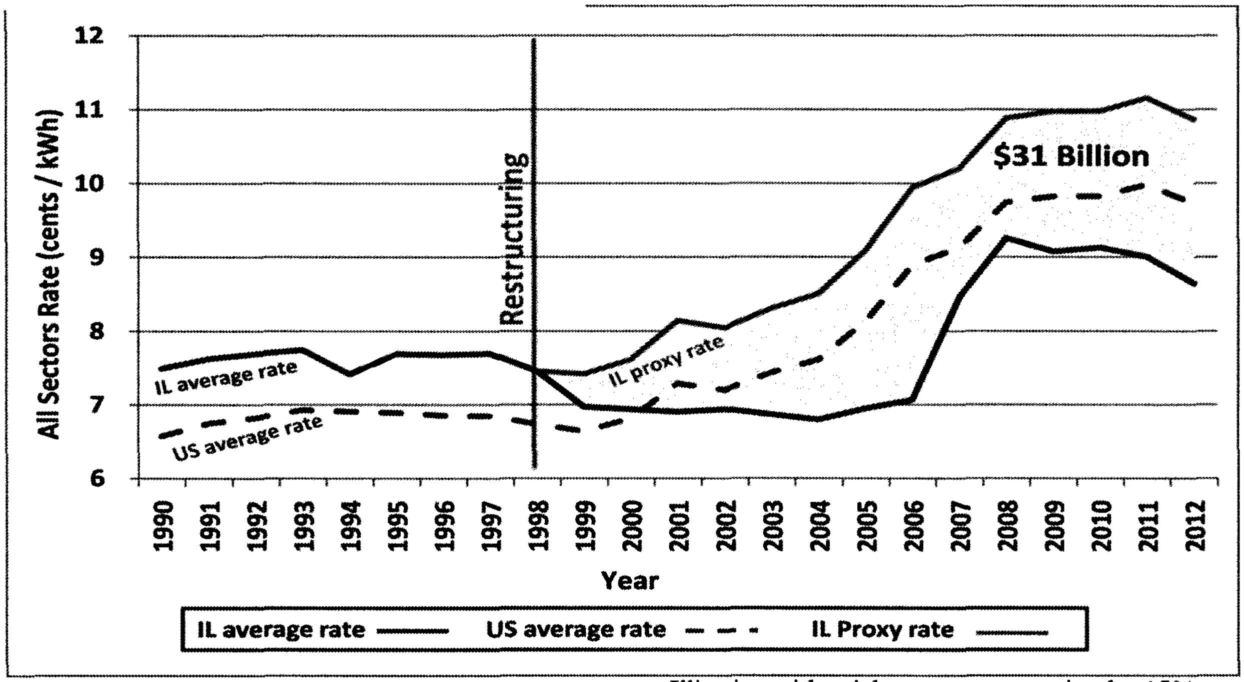
The other three states, Illinois, Michigan and Ohio undertook restructuring, but did so in quite different ways. Illinois started early and has implemented a nearly complete approach to customer choice, with large numbers of residential and small business customers now joining nearly all larger users in choosing alternative suppliers or participating in municipal aggregation. Ohio delayed aggressive restructuring until the past several years but is now moving quickly. A large portion of Ohio's residential load is now being served through municipal aggregation competitive procurement. Dr. Rose excluded Michigan from his analysis because in 2008 it largely re-instituted traditional regulation, with the exception of allowing 10% of total load to be served competitively.

Table 6 presents the yearly all-sectors price ratios for each of the five states against the U.S. averages as well as summary averages for the 1990-2000 and 2001-2011 periods.[15] Indiana has maintained a highly favorable ratio over the entire two decades, due in great part to its reliance on low-cost coal plants, a cost advantage that is under increasing pressure. Wisconsin, in contrast, has seen a deterioration of its initial favorable price ratios such that its price levels now exceed the national average. Wisconsin has tended toward a policy of reliance on relatively expensive new generation and related transmission rather than relying on the wholesale market. Ohio has maintained

[15] It should be noted that the sales and revenue figures for Illinois, Indiana, Michigan, Ohio and Wisconsin are included in the national averages.

favorable ratios during both periods of traditional regulation and of restructuring.

Figure 1 - Illinois Restructuring Savings Estimate



The divergent experiences of Illinois and Michigan are instructive. Illinois consistently pursued the opening of its electricity markets while Michigan, having started the transition to competitive choice, truncated the process and reinstalled monopoly regulation for the most part.

The Case of Illinois

Lying at the western edge of the PJM Interconnect, Illinois is bordered entirely by states that have maintained traditional monopoly regulation, among them Indiana and Wisconsin. Illinois, Indiana and Wisconsin are often in open competition for firms seeking business locations. Indeed, during the 1990s, Indiana and Wisconsin sought to attract employers with the prospect of lower electricity rates than available in much of Illinois.[16]

On August 1, 1998, the vast majority of Illinois residential customers received a 15% rate reduction mandated under the 1997 industry restructuring law while most of the remainder received 5% reductions. In the fall of 1999, following the finalization of rules and rates for delivery service by the Illinois Commerce Commission, one-third of larger industrial and commercial load became eligible to choose alternative suppliers. Over time, there were small additional residential reductions and all non-residential customers became choice-eligible. Today all customers

[16] Co-author O'Connor recalls during his time as chairman of the Illinois Commerce Commission (1983-85) seeing billboards at the Wisconsin-Illinois line urging Illinois based firms to move north for lower electricity bills. The disparity between Illinois rates, especially in the northern third of the state was an important marker in the path taken by the state to industry restructuring.

served in investor-owned utility areas can choose their supplier.

Illinois's experience, coincident with developing one of the complete transitions to customer choice, has been one of significant reductions in price ratios, going from well above the national average to consistently below the national average. Illinois swung by 19 points from a 1990-2000 average of 1.10 against the U.S. average to .91 in the 2001-2011 period.

premium and the 7% discount to average national all sector prices.

Table 7 presents price ratios for Illinois against prices for each of the other four industrial Upper Midwest states under discussion. Prior to industry restructuring, Illinois all-sectors price ratios for the 1990-2000 period averaged 1.42 against Indiana and 1.38 against Wisconsin. Following restructuring, Illinois' average against Indiana swung downward by 19 points to 1.23 and downward by 39 points against Wisconsin to 0.99 – which is below Wisconsin's all-sector 2001-2011 average price level. In 2011, the Illinois all-sectors ratio against Wisconsin was just .88, a 12 point discount.

Table 7: All-Sectors Rate Ratios
Illinois v. US Average v. Other Upper Midwest States

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1990-2000 Average
US	1.14	1.13	1.13	1.12	1.07	1.12	1.12	1.12	1.11	1.05	1.02	1.10
Indiana	1.40	1.43	1.45	1.50	1.41	1.47	1.47	1.46	1.40	1.32	1.34	1.42
Michigan	1.06	1.06	1.06	1.08	1.05	1.09	1.08	1.09	1.05	0.98	0.98	1.05
Ohio	1.27	1.25	1.27	1.25	1.20	1.23	1.22	1.23	1.17	1.09	1.08	1.21
Wisconsin	1.40	1.40	1.40	1.40	1.36	1.44	1.46	1.47	1.37	1.26	1.22	1.38
	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2001-2011 Average**
US	0.95	0.96	0.92	0.89	0.85	0.79	0.93	0.95	0.92	0.93	0.90	0.91
Indiana	1.30	1.30	1.28	1.22	1.18	1.09	1.30	1.31	1.19	1.19	1.12	1.23
Michigan	0.99	0.98	1.00	0.98	0.96	0.87	0.99	1.04	0.97	0.92	0.87	0.96
Ohio	1.04	1.03	1.02	0.99	0.98	0.92	1.07	1.10	1.01	1.00	0.99	1.01
Wisconsin	1.14	1.10	1.03	0.99	0.93	0.87	1.00	1.03	0.97	0.93	0.88	0.99

If a more conservative starting point of 1999 is considered, that being July of the previous year (1998) when the initial residential rate reduction in Illinois's choice law was implemented, the average ratio for 1990-1998 of 1.12 is significantly higher than the January 1999-June 2012 average ratio of .93. The difference in electricity spend by Illinois consumers between a 12% premium above the national average if it had persisted and the actual experience of 7% below the national average for the 1999-June 2012 period is $31 billion. The shaded area **in Figure 1** on page 9 shows the delta value between the 12%

Illinois' progress on electricity prices helps to explain the support that Illinois customers, regulators and policy makers have shown for competitive electricity markets.[17]

[17] For more information on customer choice in Illinois, see the "2012 Office of Retail Market Development Annual Report" of the Illinois Commerce Commission that can be found at

The Case of Michigan

Michigan is another story altogether. In the 1990s, prior to restructuring, Michigan prices were above the national average and then fell below the national average following its initial restructuring. However, with the reinstitution of traditional regulation and vertically integrated monopoly utilities, ratios began to rise again and now once again exceed national averages.

In 2000, Michigan enacted its electricity restructuring law. The Wolverine State, rather than emulating the doggedness of its namesake critter, employed a transition of half-measures that allowed for choice but created difficult conditions for its full implementation. In 2008 Michigan substantially re-monopolized the retail electricity market for 90% of load, while allowing 10% of load to be served under customer choice.

As shown in Table 6, Michigan made considerable progress in closing the price gap with the national average following restructuring legislation in 2000. Michigan's price ratios fell below national averages. However, following the 2008 quasi-re-monopolization, a series of utility rate increases pushed Michigan prices back above national levels and higher than those of other states in the Midwest.

http://www.icc.illinois.gov/reports/. Further, one of the important features of the competitive market in Illinois has been the role of major business trade organization in establishing endorsed partnerships with alternative electricity suppliers. The programs of the Illinois Manufacturers Association and of the Illinois Retail Merchants Association are notable in this regard.

Michigan provides a laboratory situation in which customer choice exists in parallel with traditional regulation, without the confounding problems of cross-state or regional factors being at play.

It is fairly easy to calculate the financial implications for electricity customers of the 10% limit on total load that can be served competitively. As of November 2012, annualized competitive load in Michigan's two major utilities, Consumers Power and Detroit Edison, was nearly 9.25 billion kWh. The state's major utilities are required to maintain waiting lists for non-residential customers that have asked to be allowed to purchase power from alternative suppliers.[18]

In the two utilities, more than 10,300 non-residential customers accounting for nearly 9.4 billion kWh have signed up for the waiting list. As part of the decision making process to be placed on the waiting list, many of these customers received indicative offers from suppliers. With wholesale prices that currently represent about a 2¢/kWh gap compared to higher generation components in Michigan's traditionally regulated bundled rates (5¢ v 7¢), annualized savings that are *unrealized* for business customers on the waiting list are on the order of more than $180 million.[19] If competitive market

[18] Data on the customer choice queues for Michigan's two largest utilities, Consumers Energy and DTE Energy, can be found at http://www.consumersenergy.com/content.aspx?id=2186&sid=107 and http://www.suppliers.detroitedison.com/internet/cap_tracking_system.jsp;jsessionid=QvkDnHpn65XfGRHyvG8vv1FpDX819Zv7rCGYWnnQy9NwNLLD4Ctp!460242865.

[19] This calculation is based on a similar exercise that was performed for a review of the status of

participation levels in Michigan were comparable to those in Illinois and Ohio for business and government customers, additional savings over and above those currently realized by the 11% of total load now served competitively would be on the order a half-billion dollars annually in 2013.

Future Paths

Competition proponents have often pointed out that regulatory lag and reliance on embedded costs serve to suppress prices during shortages and prop prices up during times of surplus. However, with wholesale electricity competition established as national policy, competitive forces will gradually exert increasing influence on retail rates in traditionally regulated states. Current wholesale spot and forward electricity prices are reflecting lower gas costs in rapidly declining retail prices in customer choice states. Further, competitive states are generally not as reliant on coal as are the 30 traditional monopoly states. Thus, the major question at this point is the extent to which traditional regulation and reliance on coal will deflect and defer the benefits of low gas prices. A review of the price data suggests that monopoly states have not benefited as much from low gas prices as competitive states to date, with retail rates in competitive states falling by 5% from 2008 to 2011 and retail rates in monopoly states increasing by 7% over the same time period.

The burden of proof is shifting from those who advocate customer choice to those who advocate maintenance of a regulatory model that now borders on the unique.

With the combination of falling prices and the implementation of regulatory measures that accommodate residential choice, the national share of electricity consumption by retail customers provided by competitive non-utility suppliers has grown dramatically during the 2008-2011 period of economic stress. The number of choice customers nationally increased from nearly 8.7 million in 2008 to more than 13.3 million at the end of 2011. Total electric load served by alternative suppliers increased by 40% from 488 million MWh in 2008 to 685 million MWh or 18% of total load in 2011. Growth in competitive market share has continued during 2012. There is no serious prospect of a return to the *status quo ante* of uniform traditional regulation of electricity. Even as customer choice grows in importance, there will to be two different regulatory formats operating in parallel with one another. There will be many opportunities for additional research about the relative merits of each mode of regulation.

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competitive retail electricity published in April 2012. *See* Philip R. O'Connor, Retail Electricity Choice: Proven, Growing, Sustainable, (COMPETE Coalition, April 3, 2012) at http://www.competecoalition.com/files/COMPETE_Coalition_2012_Report.pdf.

With wholesale electricity competition established as national policy, competitive forces will gradually exert increasing influence on retail rates in traditionally regulated states.

The conventional framework for public policy debates about electricity regulation is that competition and customer choice should be in the position of presenting a justification for change. That framework is increasingly obsolete and an outlier. The price of natural gas is a function of market forces. Only a small portion of telecommunications services remains subject to traditional regulation. Other network services – airlines, rail and trucking are largely free of government price setting. So far, no affirmative case has been made that traditional regulation and the monopoly model deliver benefits for consumers by controlling prices that could otherwise be set competitively and by enforcing monopoly despite worldwide examples that competitive generation and supply function perfectly well.

The burden of proof is gradually shifting from those who advocate customer choice to those who advocate maintenance of a regulatory model that now borders on the unique.

There are numerous areas of inquiry that could help to determine whether traditional regulation or customer choice in generation supply is superior in contributing to customer welfare and to the efficiency of the industry and the economy it serves.[20] Areas of inquiry might include:

- Whether it is better that price signals evident in wholesale electricity markets be conveyed promptly and transparently to end-use customers or that those price signals be mediated and delayed?
- Whether the administrative procedures that characterize price-setting in traditional regulation yield value for consumers of electricity?
- Which approach to electricity supply pricing better supports energy efficiency investment and demand response as complements to capacity and generation?
- Will renewables be better accommodated in one regulatory regime or the other?
- Which regulatory mode provides better information to business customers making investments in new facilities or energy related-equipment?

These questions and others are all long-term issues that will not be answered in any single, dispositive study but by an accumulation of research, debate and experience. ■

[20] For a fuller discussion of possible future measures of relative performance of competitive and traditional regulatory regimes, see Terrence L. Barnich and Philip R. O'Connor, *The Grand Experiment: Has Restructuring Succeeded on Either Continent?*" PUB. UTIL. FORT., Feb. 2007.

A2

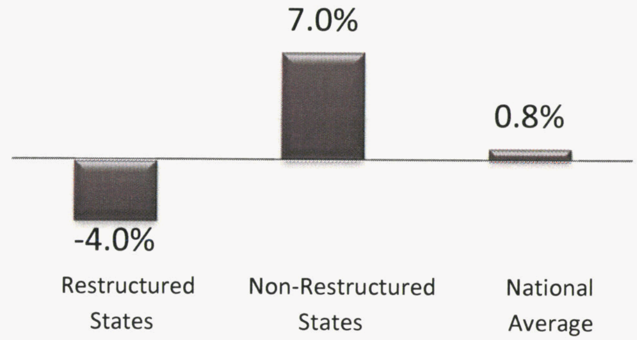
States with Restructured Electricity Markets Post Lower Rates of Change

Comparison of Rate Changes Across Electricity Markets – 1997-2012

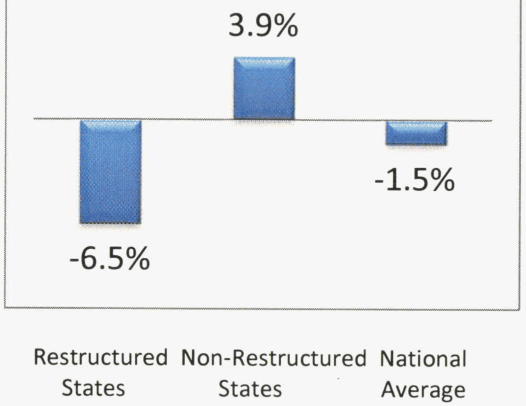
*Restructured States vs. Non-Restructured States**

COMPETE
Electricity Competition Drives Innovation and Consumer Benefits

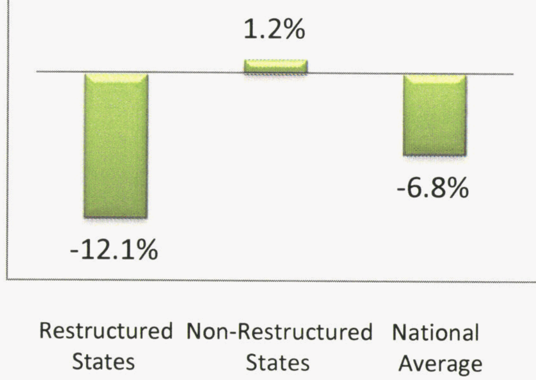
Rate Change: All Sectors



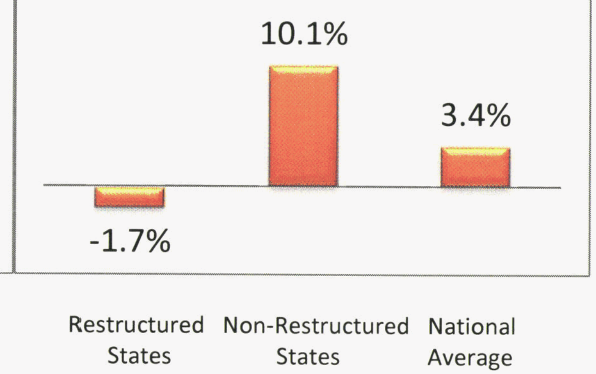
Residential Sector



Commercial Sector



Industrial Sector



* Restructured States include CA, CT, DE, IL, MA, MD, ME, MI, MT, NH, NJ, NY, OH, PA, RI, TX, and DC (17 states). These reflect states with active retail choice programs (15 states) and states with inactive/suspended retail choice programs but large portions of generation provided by Independent Power Producers (2 states). CA and MT fall in the latter category with less than 50% of net generation provided by electric utilities in 2010.

Results were calculated using price information from the U.S. Energy Information Administration (EIA) and a Consumer Price Index of Urban Consumers (CPI-U) of 43% for the period between 1997 and 2012. Sources: EIA and The Bureau of Labor Statistics)

A3

PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, PA 17105-3265

Public Meeting held February 14, 2013

Commissioners Present:

Robert F. Powelson, Chairman, Joint Statement
John F. Coleman, Jr., Vice Chairman, Joint Statement
Wayne E. Gardner
James H. Cawley, Statement
Pamela A. Witmer, Statement

Investigation of Pennsylvania's Retail Electricity Market: End State of Default Service	I-2011-2237952

FINAL ORDER

Table of Contents

BY THE COMMISSION:

By this Order, the Pennsylvania Public Utility Commission (Commission) issues its proposed model for default electric service in the Investigation of Pennsylvania's Retail Electricity Market (Investigation or RMI). This default service model was developed based on input from numerous stakeholders participating in the Investigation, as well as recommendations from the Commission's Office of Competitive Markets Oversight (OCMO). For the reasons described herein, the Commission believes that this default service model will further the development and aid in the maturation of a healthy and competitive retail electric market in Pennsylvania. Additionally, while we refer to this model as an "end state" with regard to the Investigation, we foresee the Commission's policies with regard to the competitive retail market evolving and changing to reflect market realities and experiences.

BACKGROUND AND HISTORY OF THE PROCEEDING

In its Order entered April 29, 2011, the Commission initiated an investigation into Pennsylvania's retail electricity market. *See Investigation of Pennsylvania's Retail Electricity Market*, Docket No. I-2011-2237952 (Order entered April 29, 2011) (*April 29 Order*). The *April 29 Order* tasked OCMO, with the input of stakeholders, to study how to best address and resolve issues identified by the Commission as being most relevant to improving the current retail electricity market.

Initial stakeholder input was solicited via specific questions included in the *April 29 Order*. Thirty-nine parties filed comments[1] in response to the questions, which are available on the Commission's website.[2] Additionally, these topics and comments were further discussed at the June 8, 2011 *en banc* hearing, where representatives of consumer interests, electric distribution companies (EDCs), electric generation suppliers (EGSs), subject matter experts, and regulators were invited to testify.

After review of both the written comments and the comments conveyed during the *en banc* hearing, the Commission issued an Order initiating the second phase of its Investigation. *See Investigation of Pennsylvania's Retail Electricity Market*, Docket No. I-2011-2237952 (Order entered July 28, 2011) (*July 28 Order*). In the *July 28 Order*, the Commission concluded that:

> Pennsylvania's current retail market requires changes in order to bring about the robust competitive market envisioned by the General Assembly when it passed the Electricity Generation Customer Choice and Competition Act, 66 Pa. C.S. §§ 2801, *et seq*., in 1996.

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[1] AARP, American Public Power Association, BlueStar Energy Services, Brighten Energy, Citizen Power, Inc. (Citizen Power), Citizens' Electric and Wellsboro Electric (Citizens' and Wellsboro), Citizens for Pennsylvania's Future (PennFuture), City of Philadelphia, Community Legal Services of Philadelphia (CLS), Consolidated Edison Solutions, Constellation NewEnergy, Inc. and Constellation Energy Commodities Group, Inc. (Constellation), Direct Energy Services, LLC (Direct Energy), Dominion Retail, Inc. and Interstate Gas Supply (Dominion Retail and IGS), Duquesne Light Company (DLC), Energy Association of PA (EAP), Exelon Generation Company and Exelon Energy Company, FE (Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company), FirstEnergy Solutions Corporation (FES), Future Times Energy Aggregation Group, Hess Corporation (Hess), Industrials (Industrial Energy Consumers of Pennsylvania, Duquesne Industrial Intervenors, Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance, Penn Power Users Group, Philadelphia Area Industrial Energy Users Group, PP&L Industrial Customers Alliance and West Penn Power Industrial Intervenors), Liberty Power, Mid-Atlantic Renewable Energy Association, National Energy Marketers Association (NEM), NRG Energy, Inc. (NRG), Office of Consumer Advocate (OCA), Office of Small Business Advocate (OSBA), Pennsylvania Coalition Against Domestic Violence (PCADV), Pennsylvania Energy Marketers Coalition (PEMC), Pennsylvania Utility Law Project , PPL Electric Utilities Corporation and PPL EnergyPlus, LLC (collectively, PPL), ResCom Energy, Retail Energy Supply Association (RESA), State Representative C. George, Stream Energy PA, Washington Gas Energy Services, Inc. (WGES), and York Solid Waste & Refuse Authority.
[2] http://www.puc.state.pa.us/utility_industry/electricity/retail_markets_investigation.aspx

July 28 Order at 7.

Consequently, the Commission directed OCMO to hold technical conferences to address intermediate and long-term issues pertaining to the competitive market. The Commission also directed OCMO to present specific proposals for changes to the existing retail electricity market and default service model.

OCMO held technical conferences on the following dates: August 10, 2011; August 31, 2011; September 14, 2011; September 21, 2011; September 28, 2011; October 6, 2011; October 27, 2011; November 8, 2011; November 17, 2011; December 2, 2011; January 5, 2012; February 1, 2012; March 15, 2012; and October 17, 2012. Interested stakeholders participated in these conferences and provided OCMO with information relevant to the topics that were addressed on each date.[3]

During the technical conferences, OCMO first initiated a discussion to identify intermediate steps that could be implemented to enhance the competitive market on a shorter-term basis. These discussions led to the development and issuance of several orders pertaining to the following topics: upcoming default service plans and an intermediate work plan.

In order to ensure that the next round of default service plans did not hinder the ability of the Commission to implement changes addressed within the Investigation, on October 14, 2011, the Commission issued a Tentative Order describing OCMO's recommendations for the format and structure of the EDCs' upcoming default service plans. Comments were requested on each of OCMO's recommendations. *See Investigation of Pennsylvania's Retail Electricity Market: Recommended Directives on*

[3] Recaps of these conferences are also available on the Commission's website at: http://www.puc.state.pa.us/utility_industry/electricity/retail_markets_investigation.aspx

Upcoming Default Service Plans, Docket No. I-2011-2237952 (Order entered October 14, 2011) (*October 14 Order*). OCMO's recommendations included such issues as the next default service plan time period, contract durations for upcoming default service purchases and a number of intermediate competitive enhancements that could be implemented during the next default service plan time period.

Twenty-one parties filed comments[4] to the *October 14 Order*. After reviewing the comments, the Commission entered a Final Order, which adopted recommendations with respect to the next phase of EDC default service plans. *See Investigation of Pennsylvania's Retail Electricity Market: Recommendations Regarding Upcoming Default Service Plans*, Docket No. I-2011-2237952 (Order entered December 16, 2011) (*December 16 Order*).

Intermediate issues were also discussed at the *en banc* hearing that the Commission held on November 10, 2011. Representatives of EDCs, EGSs and consumer interests presented a discussion on the following topics: consumer education, accelerated switching timeframes, customer referral programs, retail opt-in auction programs and default service plans beyond May 2013. Ten parties[5] filed informal comments following the *en banc* hearing.

After considering the remarks at, and comments following, the November 10 *en banc* hearing, on December 16, 2011, the Commission entered a Tentative Order that issued for public comment the Intermediate Work Plan (IWP). *See Investigation of Pennsylvania's Retail Electricity Market: Intermediate Work Plan*, Docket No. I-2011-

[4] AARP and the Pennsylvania Utility Law Project, Citizen Power, Citizens' and Wellsboro, Constellation, Direct Energy, Dominion Retail and IGS, DLC, Exelon Generation Company, Exelon Energy Company and PECO Energy Company, FE, Hess, Industrials, NEM, OCA, OSBA, PPL, PECO Energy Company (PECO), PennFuture, Pike County Light and Power Company (Pike), RESA, Solar Alliance and UGI Energy Services, Inc. (UGIES).

[5] Direct Energy, Dominion Retail and IGS, DLC, EAP, FE, FES, Industrials, PEMC, OCA and PECO.

2237952 (Order entered December 16, 2011) (*December 16 IWP Order*). The *December 16 IWP Order* identified issues, tasks and goals that could be resolved and implemented prior to the expiration of the EDCs' next round of default service plans, in an effort to improve the retail electricity market. The *December 16 IWP Order* provided recommendations regarding consumer education, accelerated customer switching timeframes, customer referral programs, retail opt-in auction programs, placement of the default service Price to Compare (PTC) on customer bills and mechanisms for increased EDC and EGS coordination. Two programs, the Retail Opt-in Auction and Standard Offer Customer Referral Programs, were specifically proposed for inclusion in the EDCs' upcoming default service plans.

Twenty-three parties filed comments[6] and thirteen parties filed reply comments[7] to the *December 16 IWP Order*. Following a careful consideration of the comments and reply comments that were filed, on March 2, 2012, the Commission entered a Final Order that adopted the IWP and directed that the proposals included therein be implemented prior to the expiration of the next round of the EDCs' default service plans. *See Investigation of Pennsylvania's Retail Electricity Market: Intermediate Work Plan*, Docket No. I-2011-2237952 (Order entered March 2, 2012) (*March 2 Order*).

Subsequent to addressing intermediate issues and the IWP, the Investigation moved to a discussion of the end state of default electric service in Pennsylvania. On March 21, 2012, the Commission held an *en banc* hearing where EDCs, EGSs and representatives of consumer interests shared their perspectives on three proposed end state default service models, which OCMO developed and distributed for discussion prior

[6] AARP, the Pennsylvania Utility Law Project and CLS, Citizen Power, Citizens' and Wellsboro, Constellation, Direct Energy, Dominion Retail, DLC, Exelon Generation Company and Exelon Energy Company, FE, FES, Industrials, NEM, OCA, PCL&P, PECO, PEMC, PPL Electric Utilities Corporation, RESA, Spark Energy, L.P., UGIES, UGI Utilities, Inc. – Electric Division, Wal-Mart Stores East, LP and Sam's East, Inc. (Wal-Mart) and WGES.
[7] AARP, the Pennsylvania Utility Law Project and CLS, Citizens' and Wellsboro, Direct Energy, Dominion Retail, DLC, FE, FES, Industrials, OCA, PECO, PCADV, PEMC and RESA.

to the *en banc* hearing.[8] In each of the three models, EGSs served in the default service role with variations proposed for the default service product. In Model A, default service would be provided on the basis of real-time/hourly PJM Interconnection, LLC. (PJM) locational marginal pricing (LMP) and an administrative adder. Prices would change monthly (or more frequently) and not be reconciled. In Model B, default service would be provided on the basis of prevailing market prices, as established through an index, auction or other acceptable method. Prices would change quarterly or semi-annually and not be reconciled. In Model C, default service would mirror the existing procurement framework. Prices would change quarterly or semi-annually and be reconcilable on a twelve-month rolling basis.

Also at the March 21 *en banc* hearing, various small and medium businesses presented their experiences with shopping for electricity. In addition, the Commission heard from a panel of speakers who discussed the development of a comprehensive statewide consumer education program and ways to fund those consumer education efforts. Twenty-one parties filed informal comments[9] following the March 21 *en banc* hearing.

On November 8, 2012, the Commission entered a Tentative Order that issued for public comment a proposed end state model for default electric service in Pennsylvania. *See Investigation of Pennsylvania's Retail Electricity Market: End State of Default Service*, Docket No. I-2011-2237952 (Order entered November 8, 2012) (*Tentative Order*

[8] The discussion document is available at http://www.puc.state.pa.us/electric/pdf/RetailMI/RMI-SecLtr_Staff_Doc_EnBanc_Hearing030212.pdf

[9] AARP, the Pennsylvania Utility Law Project and CLS, Citizen Power, Citizens' and Wellsboro, Direct Energy, Dominion Retail and IGS, DLC, EAP, Exelon Generation Company, Exelon Energy Company, Constellation NewEnergy, Inc. and PECO Energy Company, FES, FE, Industrials, Mid-Atlantic Renewable Energy Coalition (MAREC), NRG, OCA, PCADV, PennFuture, PEMC, RESA, Solar Energy Industries Association and PA Solar Energy Industries Association (SEIA and PASEIA), Wal-Mart and WGES.

or *November 8 Order*). Comments were due within thirty days of entry of the *November 8 Order*.

The following parties filed comments to the *Tentative Order*: AARP, the Pennsylvania Utility Law Project, PCADV and CLS (collectively, PULP); Citizen Power; Citizens' and Wellsboro; COMPETE Coalition (COMPETE); ConEdison Competitive Energy Businesses (ConEd); DLC; Electric Generation Supplier Parties (EGSP); Electric Power Generation Association (EPGA); Electric Power Supply Association (EPSA); EAP; Exelon Generation Company, Constellation Energy and PECO Energy Company (collectively, PECO); FES; Industrials; FE; MAREC; Mid-Atlantic Solar Energy Association and Pennsylvania Solar Energy Industry Association (MSEIA & PASEIA); NEM; NRG; OCA; Pennsylvania Chamber of Business and Industry (PA Chamber); PCADV; PEMC; PennFuture; Pike; PJM Power Providers Group (P3); PPL; PULP; RESA; The Sierra Club (Sierra Club); Verdigris Energy, LLC (Verdigris); and WGES.[10]

END STATE OF DEFAULT SERVICE

Upon consideration of the entire record developed in the Investigation, including remarks presented at the *en banc* hearings, written comments (particularly those filed to the *Tentative Order*), and staff recommendations as set forth in the *Tentative Order*, the Commission has developed the following model for the end state of default electric service in the Commonwealth.

[10] The Commission received comments from EverPower Wind Holdings, Inc. on December 13, 2012. These comments will not be considered as they were filed after the final date to submit comments to the *November 8 Order*. In addition, the comments of EverPower Wind Holdings, Inc. responded to specific comments that other stakeholders submitted. It would be inequitable to consider the comments of EverPower Wind Holdings, Inc., given that they essentially constituted reply comments and no other party had an opportunity to file reply comments to the *November 8 Order*.

The topics addressed in this Final Order include the following: guiding principles for the end state; a definition of default service provider (DSP); definitions of the default service products to be offered to various retail electric rate classes; a timeline for the implementation of the new default service model; a discussion of applicable consumer protections; a discussion of the portability of customer assistance program (CAP) benefits for low-income customers; a discussion of the potential implementation of supplier consolidated billing (SCB); a plan for the implementation of accelerated switching; a discussion of the provision of metering services, including net metering services; a discussion of the provision of Energy Efficiency and Conservation (EE&C) programs; a discussion of logistics for existing and future long-term contracts, including those for Alternative Energy Credits (AECs); a plan for the implementation of a statewide consumer education campaign; and a discussion of regulatory costs and assessments.

A. Guiding Principles

In developing a framework to move Pennsylvania toward a more competitive market for electricity and establish a better platform for the sustainability of the competitive market, the Commission has relied on several underlying principles. These principles include the Commonwealth's legislative policy favoring competition over regulation; a continuation of fundamental consumer protections; structuring the default service model to more closely reflect current market conditions; and encouraging investment by EGSs that results in innovative and competitively-priced product offerings for consumers.

Since 1996, with passage of the Electricity Generation Customer Choice and Competition Act, 66 Pa. C.S. §§ 2801, *et seq.* (Competition Act), the legislative policy in the Commonwealth has called for a competitive electric generation market to replace the regulated electric generation market. In passing the Competition Act, the General Assembly declared as a matter of policy that "[c]ompetitive market forces are more effective than economic regulation in controlling the cost of generating electricity." 66 Pa. C.S. § 2802(5). The General Assembly further recognized that the "cost of electricity is an important factor in decisions made by businesses" when "locating, expanding and retaining facilities in the Commonwealth." 66 Pa. C.S. § 2802(6). Due to the importance of a competitive retail market in controlling electric prices, the General Assembly found that this "Commonwealth must begin the transition from regulation to greater competition in the electricity generation market to benefit all classes of customers and to protect this Commonwealth's ability to compete in the national and international marketplace for industry and jobs." 66 Pa. C.S. § 2802(7).

Following passage of the Competition Act, the Commission immediately embarked upon implementation, which entailed the issuance of interim guidelines, the promulgation of regulations and the review and approval of restructuring plans filed by the EDCs. Throughout the implementation process, the Commission has remained committed to the successful development of the retail electric market in Pennsylvania, always vigilant of the need to balance regulatory requirements aimed at consumer protection against policies designed to facilitate entry and participation in the market by EGSs.

In launching this Investigation in April 2011, the Commission recognized the need to assess the current status of the retail electric market and explore changes that may be needed to allow customers to more fully realize the benefits of competition. Following a review of comments and testimony offered at the June 8, 2011 *en banc* hearing, the Commission reached the "inescapable conclusion that Pennsylvania's current retail market requires changes in order to bring about the robust competitive market envisioned by the General Assembly when it passed" the Competition Act. *July 28 Order,* page 7.

While shopping statistics alone are not indicative of the success of a competitive market, we note that, as of February 13, 2013, nearly two-thirds of Pennsylvania's electric customers still received electric generation supply from their EDCs.[11] Despite a large number of EGSs in the market, many offers are only slightly below each EDC's PTC and few innovative product offerings have emerged to date that attract residential and small commercial customers into the competitive retail market.

As discussed throughout this Final Order, EGSs face any number of challenges to operate in the current competitive environment, which hinders consumers' ability to enjoy a fully functioning competitive market. The primary price signal provided to consumers is the EDC's PTC. However, due to reconciliation and the mix of contracts that EDCs use to establish the PTC, EGSs must compete with a PTC that often is not correlated to wholesale energy markets and may move in directions opposite that of wholesale energy markets trends. This can inhibit consumers' ability to make informed decisions due to the receipt of false or misleading price signals.

Other issues, like the inability of EGSs to issue consolidated bills to customers; the lengthy switching process that is linked to EDC meter read dates; and the requirements that new customers receive service from the EDC and moving customers revert back to the EDC before moving to a competitive supplier makes the relationship between the EGS and the customer tenuous at best. This dynamic can result in customer confusion and hesitancy among EGSs to invest more resources in the Commonwealth. It most certainly does not foster a robust and vibrant competitive market in Pennsylvania, as envisioned by the Legislature.

In this Final Order, the Commission is outlining fundamental long-term changes to the underlying default service structure. The Commission is confident that the various

[11] We note that the Code allows for either an electric distribution company or a competitive supplier to fulfill the default service role. Currently, the default service roles across all service territories are fulfilled by electric distribution companies. Because of this, we use the terms "default service provider" and "electric distribution company" interchangeably throughout this Order. We do not, however, intend for this to be a signal that we expect that the default service role will always be fulfilled by electric distribution companies.

intermediate measures underway, including Standard Offer Customer Referral and Retail Opt-in Programs, will improve the overall operation of the competitive market in the near term. However, the testimony and comments filed in this Investigation have convinced us that the development and sustainability of the retail market will continue to lag behind our expectations until we effectively address the fact that the currently-structured default service product does not reflect current market conditions. The changes we seek to implement will provide default supply prices that bear a closer resemblance to market conditions. These changes will also provide a regulatory framework that encourages substantial EGS investment in Pennsylvania's retail electric market. We believe this will move the Commonwealth towards a robust competitive market, where a large number of suppliers provide customers with a wide array of competitively-priced generation supply products and offerings from which to choose.

Act 129 of 2008, P.L. 1592, added extensive language to Section 2807 of the Public Utility Code (Code), 66 Pa. C.S. § 2807, to require the default service product to fulfill a variety of statutory requirements, moving away from a default service product that reflected "prevailing market prices." Section 2807 (e)(3.2) mandates that the electric power procured by the DSP include a prudent mix of contracts. In addition, Section 2807 (e)(3.6) requires the filing of competitive procurement plans by DSPs, on which hearings must be held as necessary and Commission Orders entered prior to commencement of the competitive procurement process. To implement these mandates, the Commission has promulgated regulations setting forth the various requirements for these plans. The initial plans were required to span two to three years, 52 Pa. Code § 54.185 (d), and while the Commission has flexibility as to the time period the plans cover, any shorter period would likely result in too frequent litigation for the EDCs and intervening parties. Necessarily, these plans rely on forecasting energy prices and, because they span two to three years, the resulting prices contain varying levels of risk premiums. When the quarterly reconciliation process (which makes the EDCs whole despite errors in forecasts) is layered over these price projections, risk premiums and EDC reconciliation accounting practices, the result is that EGSs are competing with a PTC that, at any given time, may not be reflective of current market conditions.

Two basic problems result from this structure. First, during periods when market prices are lower than the EDC's PTC, EGS offers are frequently driven by the PTC. In those circumstances, the EGS offers often remain close to the above-market PTC and consumers do not fully realize the benefits of the lower market prices. Under a model where the default service product more closely reflects market conditions, the market should be the primary factor driving EGS prices, which is consistent with the purposes of the Competition Act.

A second concern about the existing structure is that when market prices rise, EGSs find it difficult to compete with a PTC that may reflect both prices that are not market-responsive and the EDC's obligation to refund over-collections (artificially decreasing the PTC). A continuation of this structure exposes the Commonwealth to the risk that, when market prices increase and PTCs are artificially depressed by EDCs that have over-collected from ratepayers, EGSs will exit the Commonwealth. While consumers may not initially be harmed because they will have access to the EDCs' PTCs for the remainder of the term, that exit would likely signal the end of the retail electricity market in Pennsylvania. That is what occurred in 2001, and the Commission is not confident that another restart of the market would be possible.

The expiration of generation rate caps in 2009 and 2010 was a major factor breathing new life into the electric retail competitive market and, since that was a one-time event, it would be difficult to once again attract EGSs to Pennsylvania. Absent a robust competitive market for electricity, consumers' only option would be the default service supplier. Pennsylvania would not have the current situation of many active EGSs and competitive offers or realize the potential of a variety of innovative product offerings that are available to consumers in a properly-functioning market. Without the changes proposed herein, this Commission has substantial concerns that the current retail electricity market construct will not be viewed as sustainable by EGSs. By ensuring a robust competitive electricity market, the Commission believes long-term energy costs will be reduced and EGSs will be better able to price their offerings, leading to less customer confusion, lower prices and a broader array of products available to all Pennsylvanians.

So, while the stated intention of the Act 129 statutory requirements added in 2008 was to ensure adequate and reliable service at the "least cost to consumers over time," 66 Pa. C.S. § 2807(e)(3.4), some interpretations of these mandates have had the unintended effect of creating a default service product that bears little or no resemblance to market conditions. They have also unnecessarily hampered the Commission's ability to develop a regulatory framework that encourages investment by EGSs and a robust competitive market. Further, it is not clear that the statutory requirements, as applied, have produced the "least cost to consumers over time" during the past few years. Spot market prices tend to produce the "least cost to consumers over time" because lower risk premiums are included in spot-market-priced contracts due to the reduced uncertainty of recovery for wholesalers of costs related to generation and transmission services.

Therefore, the Commission, through this Final Order, recommends fundamentally changing the default service product so that it more closely resembles market conditions. Through the changes proposed herein, the Commission hopes to create a structure where the market drives prices charged by EGSs, where EGSs expand their investment in Pennsylvania due to certainty and a more level playing field, and where consumers enjoy competitive prices and a wide variety of innovative product offerings. In this manner, the Commission expects Pennsylvania to achieve and sustain the robust competitive market that was envisioned in 1996 by the General Assembly.

The Commission recognizes that some of the changes proposed herein may require amendments to the existing legislation and Commission regulations. Since we believe it is critical to move forward quickly while many EGSs are actively participating in the market, we are prepared to devote the resources needed to effectuate these changes so that our changes to the default service product can go into effect on June 1, 2015.

B. Provision of Default Service

In its *Tentative Order,* the Commission proposed to retain the EDC as the DSP and continue to permit the EDC to obtain full cost recovery. We further proposed that the EDC remain in the DSP role unless the Commission approves an alternative DSP entity pursuant to Section 2803 of the Code, 66 Pa. C.S. § 2803, and the Commission's regulations on default service at 52 Pa. Code § 54.183. Lastly, we proposed that an alternative DSP may be selected through one of the following means: (1) an EDC may petition to be relieved of its default service obligation; (2) an EGS may petition to be assigned the default service role in a particular EDC service territory; or (3) the Commission, upon its own motion, may propose that an EDC be relieved of its default service obligation. 52 Pa. Code § 54.183(b)(1)-(3).

1. Comments

OCA, the Industrials, Citizens' and Wellsboro, PECO, PPL and Citizen Power support the Commission's proposal to retain the EDC as the DSP.

OCA asserts that the EDC is best positioned to provide default service in the most cost-effective manner. The EDC is tasked to keep electricity flowing regardless of the entity that serves as DSP. Further, OCA submits that since the EDC is tasked with maintaining its distribution system, the EDC is in an ideal position to serve as DSP to ensure all customers receive electric service regardless of electric generation supplier performance. OCA at 7.

The Industrials assert that, although the Commission's proposal reserves the Commission's right to select and alternative DSP, the EDCs' proven track record of reliable default service provides support for the EDCs' continued performance of such service to all customers, unless the EDC is unable to do so. Industrials at 9.

PPL submits that the EDC or an alternative DSP should be subject to the same regulations and, therefore, should have the right to recover the costs of administering default service on a full and current basis. PPL further submits that allowing the EDC to exit the role of DSP will help to alleviate customer confusion as to the EDC's true role as a "delivery" business that provides the same level of service regardless of a customer's generation supply decisions. Consequently, PPL states that it would be inappropriate to establish the EDC as the permanent provider of default service. PPL at 8.

PECO states that continuing the role of the EDC as the DSP will provide certainty of default service supply and retail market infrastructure for customers and market participants as the competitive landscape continues to evolve. Further, PECO submits that the Commission's existing authority to approve an alternative DSP provides an adequate process for the selection of an alternative DSP should future changes be appropriate. PECO at 5.

Citizens' and Wellsboro submit that the Competition Act and the Commission's Regulations permit the Commission to authorize an alternative DSP. Consequently, Citizens' and Wellsboro contend that it would be beneficial if the Commission provides clarity on how an alternative DSP would be implemented. For instance, Citizens' and Wellsboro seek clarity on whether the implementation of an alternative DSP would, in effect, permanently relieve the EDC of the responsibility. Further, Citizens' and

Wellsboro proposes a specific option to create an "agency" backstop to serve as the DSP if an alternative DSP fails. This agency backstop could be made up of EGSs that provide backstop service at spot market rates. Citizens' and Wellsboro at 3 and 4.

FE avers that any proceeding that determines a potential alternative DSP should occur outside of the EDC's default service proceedings and the transition should coincide with the implementation of a new default service term. FE at 2 and 3.

WGES submits that the ideal end state is one in which the default service role is fulfilled by an EGS. As such, WGES agrees with the Commission's recommendation to retain the authority to revisit to concept of placing an EGS in the DSP role at a future point in time. WGES at 1.

NRG contends that retaining the EDC in the DSP role will not result in the development of robust sustainable retail competition and will not completely unlock the full array of innovative products and services. NRG submits that only when the EDC has been removed from the DSP role will a fully functioning, robust, and sustainable competitive market be realized. Further, NRG states that having the EDC exit the DSP role will enable the EDC to focus on its core competencies and obligations for safe and reliable distribution service. Consequently, NRG avers that retaining the EDC in the DSP role should be viewed as a transitional step toward full competition, as opposed to the "end state." NRG, therefore, urges the Commission to set a timeline for the replacement of the EDC as the DSP. NRG at 5.

PEMC expresses concerns that the Commission proposal to permit the implementation of an alternative DSP in the future could merely result in the establishment of a new de facto monopolist. PEMC contends that a single EGS acting as a DSP is not in the interests of the competitive marketplace. Consequently, PEMC offers three potential options to restructure default service in order to truly advance the competitive marketplace and benefit consumers. The first option is to eliminate utility-provided default service and transition non-shopping customers to certified EGSs through an open auction. The second option is to retain the EDC in the DSP role but require a premium be placed on the default service price to compensate EDCs for maintaining a non-core business, to reflect the value placed on default service by customers who made an effective choice to stay on default service, and to recognize that the default service price is subsidized since it does not contain all the costs of providing and receiving competitive service. The third option is to retain the EDC in the DSP role but unbundle commodity costs from distribution rates, incorporate those unbundled costs in the PTC, and eliminate utility reconciliation for commodity costs. PEMC at 5 and 6.

EGSP raises concerns similar to those expressed by PEMC. Specifically, EGSP emphasizes that the default service price must contain all costs of providing the service, noting that there are costs that would be built into the retail commodity rate if this service was provided by a retail provider in a truly competitive environment. EGSP at 4.

RESA disagrees with the Commission's proposal. RESA avers that default service can, and should, be fulfilled by competitive EGSs rather than the EDC. In support, RESA submits that retaining the EDC in the DSP role presents structural barriers that impede market development and prevent customers from realizing the benefits of a fully workable and competitive market. RESA states that the Commission's overall proposal in the *Tentative Order* will continue to provide the EDC, as the DSP, a competitive advantage over EGSs. Consequently, RESA submits that the Commission should remain open to implementing other reforms appropriate to achieve the goal of robust competition. Lastly, RESA contends that any legislative changes the Commission chooses to pursue should not foreclose the possibility of further market refinements, such as those advocated by RESA. RESA at 4 and 5.

2. Resolution

Upon review of the comments, we are persuaded to adopt our initial proposal to retain the EDC in the DSP role. The Commission believes the various revisions to the default service product that we direct within this proceeding are a reasonable step in the evolution of Pennsylvania's retail electric market. In the future, the Commission may revisit the concept and merits of adopting an alternative DSP or DSPs. We acknowledge the arguments of those parties who state that keeping the EDC in the DSP role presents structural barriers to a robust retail market place and that the EDCs should focus on their core competencies. However, we believe that, at this time, it would be most prudent to be patient and allow the revisions proposed in this proceeding to be implemented. As we stated in our *Tentative Order*, we continue to believe that, at this time, permitting the EDCs to continue to provide default service strikes an appropriate balance that allows the retail electric market to continue its fairly steady progress of organic growth while providing the Commission with the ability to take further action in the future, if necessary. *Tentative Order* at 14.

Although we are keeping the EDCs in the default service role, we emphasize that our decision has no basis in the rationale offered by the Industrials relating to continued reliability of service. To the contrary, we view the EDCs as responsible for the reliable delivery of electric service regardless of the entity providing default generation service.

The Commission agrees with Citizens' and Wellsboro that clarity is necessary regarding the implementation of a model in which an alternative entity, or multiple entities, provides default service to customers. To provide such clarity, we direct OCMO to convene a working group to identify issues related to the implementation of such a model. OCMO shall provide recommended solutions to the Commission no later than

November 15, 2013.[12] At a minimum, we envision that this working group will provide recommendations regarding the potential for cost recovery; the timeline in which an alternative entity would begin providing default service; whether or not multiple entities could provide default service within a single EDC's service territory; and the potential provision of net metering benefits.

As to the comments suggesting a further unbundling of commodity costs from distribution rates to ensure that the PTCs reflect all costs of default service, the Commission agrees with this concept and has strived to address these issues as they have arisen in distribution rate cases. At this time, however, the Commission is not inclined to launch any generic investigations or promulgate regulations requiring such further unbundling as we believe these measures would be a significant undertaking and require the time and resources of many stakeholders. We would prefer to focus available resources on the changes we have identified, keeping in mind that this does not preclude the Commission from addressing the further unbundling of commodity costs and distribution rates in another proceeding in the future.

C. Applicability of Proposed End State

In its *Tentative Order*, the Commission proposed that the changes be applicable to all jurisdictional EDCs to achieve and sustain the robust competitive market that was envisioned with the passage of the Competition Act. The Commission believed that such a market should be available statewide, regardless of the size of the EDC. Comments were sought regarding the feasibility of such a model being implemented in the service territories of smaller jurisdictional EDCs. *Tentative Order* at 14.

[12] While OCMO will address all stakeholder viewpoints when providing its recommendations to the Commission, we will not require that consensus be met.

1. Comments

The Industrials, PECO, PEMC, PPL and RESA agree with the Commission's proposal that the changes proposed in the *Tentative Order* be applicable to all jurisdictional EDCs in Pennsylvania. Industrials at 9; PECO at 6; PEMC at 6; PPL at 9; RESA at 6. PPL does note, however, that certain aspects of the model do not apply to smaller EDCs. These aspects are the provision of EE&C programs under 66 Pa. C.S. § 2806.1 and the procurement and installation of smart meters under 66 Pa. C.S. § 2807(f), specifically 66 Pa. C.S. § 2807(f)(6). Accordingly, PPL avers that the smart meter aspects of the Commission's proposals regarding accelerated switching may be difficult for smaller EDCs to achieve. PPL at 9.

Citizens' and Wellsboro urge the Commission to retain flexibility in the applicability of these changes, and consider the impacts of the proposed default service structure on small EDCs. Citizens' and Wellsboro at 4. Similarly, Pike states that the general rules that apply to EDCs should not apply to them. Pike avers, that because the majority of its customers are already participating in the retail market, because it is a small company and because it is part of a different regional transmission organization (New York Independent System Operator, as opposed to PJM), it should not be viewed similarly to the other Pennsylvania EDCs. Pike believes that the Commission should exempt small EDCs and/or those EDCs with significant levels of EGS penetration from having to make some of the recommended changes from the *Tentative Order*. Pike at 5.

OCA does not support the Commission's proposed applicability of its end state model, as it does not support the model as a whole. Additionally, OCA notes that, given the differing sizes of the EDCs, a "one size fits all" approach is unworkable. OCA at 8.

2. Resolution

The Commission maintains its position that the changes included within this end state model be applicable to all jurisdictional EDCs. This will provide uniformity and benefits statewide. However, our determination here does not preclude a smaller EDC from submitting, for the Commission's review, a petition that provides evidence as to why it may not be appropriate, beneficial to customers or feasible to implement this model or specific requirements in its service territory.

The Commission would like to clarify that those obligations in the Code regarding the provision of EE&C programs, 66 Pa. C.S. § 2806.1, and the procurement and installation of smart meters under 66 Pa. C.S. § 2807(f)(6), will not be applied to smaller EDCs with this end state model, nor will such application be included in proposed legislative changes. Those obligations will remain with the larger EDCs, as outlined within the statute.

D. Default Service Product

Given the Commission's decision to not seek to remove EDCs from the DSP role, it becomes paramount to change the products offered by DSPs so as to enhance the ability of EGSs to compete on a level playing field. Since the EDCs will maintain the right to full cost recovery for their provision of default service, the EDC has an entirely different exposure to risk than an EGS. Under the current construct, the EDC purchases large portions of load months, and even years, in advance of delivery. This, in turn, creates the potential for a situation in which the PTC is based more on historical market conditions than that at the time of delivery. Further exacerbating this issue are the instances when the EDC's PTC fails to reflect the actual cost of service due to inaccurate customer migration projections, certain accounting practices or inaccurate spot market price projections. These inaccuracies can lead to the inclusion of significant reconciliation costs within the PTC that have little or no relationship to the present market for energy and, therefore, can potentially further move the PTC away from market conditions at the time of delivery.

EGSs primarily operate in current market conditions. EGSs do not have any right to cost recovery and, as such, pricing corrections, as implemented through EDC reconciliation processes, do not play any role in their price offers to customers.

Consequently, the Commission's main goal in developing a revised default service product is to create a more market-based PTC. This type of product will mitigate the potential for "boom/bust" scenarios to occur. "Boom" scenarios are those in which the EDC's PTC is inflated when compared to market price indicators at the time. In this situation, the PTC acts as an artificial price ceiling under which EGSs set prices to attract waves of customers. As explained earlier, this boom scenario will enable EGSs to beat the EDC's PTC, but may not provide shopping customers with prices pegged to lower market price indicators.

"Bust" situations are those in which the EDC's PTC is substantially lower than market priced indicators. In this situation, customers will, in many cases, revert back to default service because EGSs cannot beat the PTC that the EDCs formulated with their no-risk procurement portfolio. As explained previously, such a scenario may benefit customers in the short term, but in the long term, such a scenario is likely to drive EGSs out of the market, as occurred in 2001, thereby eliminating consumers' ability to shop for a lower price when the default service price rises. Therefore, the elimination of potential "boom/bust" cycles will create a more sustainable retail market, which, in turn, should lead to enhanced product offerings to consumers and long-term EGS investments within Pennsylvania. With this rationale, the Commission seeks to implement the default service products and procurement strategy described below.

1. Medium and Large Commercial and Industrial Rate Classes

In the *Tentative Order*, the Commission proposed that EDCs offer hourly LMP for medium and large commercial and industrial (C&I) accounts through quarterly auctions. For accounts in this group that do not have interval meters, the Commission proposed that EDCs charge hourly LMP by using customer load profiles. Noting that LMP pricing is already offered to large C&I customers,[13] the Commission suggested that medium C&I customers are equally well-equipped and educated to manage their commodity costs in an hourly LMP default service environment. The Commission described this proposal as a natural progression for the retail marketplace and opined that having EDCs offer hourly LMP to these accounts will put EGSs on a level playing field for competing not only with the PTC but with each other. *Tentative Order* at 16-17.

Additionally, the Commission recognized that there is currently no uniform delineating point across the EDCs to distinguish these accounts from small C&I accounts. By way of general guidance, the Commission suggested that EDCs offer hourly LMP to accounts with demand of 100 kilowatts (kW) or greater. The Commission also proposed that EDCs be permitted to designate a delineation point between small C&I customers and medium and large C&I customers based on existing rate schedules, where it is impractical to create default service subclasses. *Tentative Order* at 16.

a. Comments

Several parties support the Commission's proposal to implement an hourly-priced product for medium and large C&I customers. As explained by NRG, a default service product that more closely resembles market conditions over time is necessary to spur

[13] For the purposes of this proceeding, the Commission defines large C&I customers as those with demand of 500 kW or greater.

competition to the next level. NRG at 6. RESA describes the Commission's goal of a more market-based PTC as a "good step forward in the transition to an optimal end state where a fully robust competitive market exists." RESA at 6. PECO notes that virtually all of these customers are now shopping and have the ability to secure the types of products and services they desire from EGSs. PECO at 6. PPL explains that it currently provides real time default service to C&I customers whose peak load contribution is greater than 500 kW and that it has already stated its intent to expand this service to customers with demands of less than 500 kW but greater than 100 kW in its next default service plan with an implementation date of June 1, 2015. PPL at 11. The Industrials indicate that if a handful of safeguards are adequately addressed, they are not opposed to the continuation of hourly LMP pricing as the default service option for large C&I customers or the extension of that product to medium C&I customers. Industrials at 4.

As to the use of an auction process, the Industrials propose that the hourly-priced services should be provided by EDCs, not auctioned to other suppliers, claiming that this approach will result in the most cost-effective adder. The Industrials explain that dividing the small amount of large C&I customers relying on default service among multiple wholesale suppliers would not be efficient or produce a just and reasonable result. Industrials at 4 and 5.

If an auction process is used, the Industrials suggest that it should be conducted annually, rather than quarterly, to help keep the administrative costs reasonable. Industrials at 4. PPL observes that since most of the components of this product are determined by PJM markets, the administrative adder will be the only component subject to competition among suppliers. Therefore, PPL suggests that any additional savings resulting from more frequent competition may not justify the administration burden of procuring more often than annually. PPL at 13.

The Industrials also propose conditions to avoid cost shifting among medium and large C&I customers. Specifically, the Industrials contend that only customers who are new to this hourly product should pay costs associated with implementation, and separate procurements should occur to minimize interclass cost shifting. They explain that the characteristics of the "large" and "medium" C&I customers differ on issues such as creditworthiness, predictability of usage and payment history, which could translate to higher risk premiums for serving the smaller customers. The Industrials further note that allocating, collecting and reconciling any default service charges for capacity and transmission for all hourly price customers in accordance with the PJM rates and rate design for each product will avoid interclass and intraclass cost shifting. Industrials at 5.

The Industrials further maintain that a failsafe mechanism needs to be in place to address the possibility of market failure, such as a situation where no EGSs are offering products that respond to the customers' needs. Specifically, the Industrials suggest that the Commission ensure it has sufficient flexibility under the statute to step in and revise the default service paradigm if necessary. Industrials at 7 and 8.

PECO, PPL and FE contend that the proposal to use load profiles to establish hourly prices for medium and large C&I customers without interval meters is not feasible or supported by current billing systems. PECO asserts that issues associated with reconciliation of real-time load obligations and load profiles would complicate the provision of LMP-based default service to customers in the absence of interval meters. PECO at 7. FE explains that billing these customers on the basis of load profiles would mean that no load-shedding strategy would relieve them of high LMP prices. Additionally, FE notes that it would need to program functionality into its billing system to use load profiles to price hourly LMP for medium C&I customers who do not have interval meters. FE at 4 and 5.

PPL points out that relying on load profiles would produce a bill that is calculated by multiplying a rate by an estimate of usage and is not reflective of the customer's own usage pattern. Noting that the customers who fall into this group (i.e. customers with demands of less than 500 kW but greater than 100 kW) represent a wide variety of customers with diverse usage patterns, PPL expresses concerns about how a representative load profile would be established. DLC echoes these concerns, noting that it does not have the capability to use load shapes to determine actual hourly consumption. DLC at 4. PPL suggests that the better way to move closer to market-based prices for these customers is to expand the deployment of interval meters and smart meter capabilities. PPL at 11 and 12.

With respect to the proposed threshold of more than 100 kW of demand to distinguish medium and large C&I customers from small C&I customers, PPL and PECO concur with this delineation point. PPL at 11; PECO at 6 and 7. FE states that Metropolitan Edison Company, Pennsylvania Electric Company and Pennsylvania Power Company have a delineation of 400 kW, which is the level at which interval metering is installed and the hourly LMP default service product is offered under the default service plan that goes through May 31, 2015. As to West Penn Power Company, FE explains that it has a rate schedule delineated at the 100 kW level, but its requirement for interval metering does not begin until 500 kW of demand. FE at 5. DLC notes that it does not currently have the infrastructure capable of providing hourly priced service to C&I customers below demands of 300 kW and therefore recommends that lowering the threshold for hourly priced service below that level should await the completion of smart meter deployment. DLC at 4.

RESA cautions against providing too much latitude to the EDCs to define the appropriate customer-size threshold for the hourly LMP product. Recognizing that EDCs currently have in place different tariff rate classifications and different default service procurement group classifications, RESA urges the Commission to require EDCs to expand hourly-priced default service to a larger group of medium C&I customers rather than relying on existing definitions. RESA at 7-9.

Pike seeks to be exempted from the Commission's proposal regarding the default service product as it already provides default service at spot market prices and will continue to do so under its approved plan for the period from June 1, 2012 through May 31, 2014. Noting that this approach is wholly consistent with the Commission's stated goal of creating EDC default service products that are more market-based, Pike also refers to difficulties it would have in conducting quarterly auctions for its supply since it would have to negotiate and enter into a contract with a merchant generator and pay an unjustified premium given the small amount of default service load to be served. Pike at 6 and 7.

b. Resolution

As was noted in our *Tentative Order* and many of the comments, hourly LMP is already offered to large C&I customers, and medium C&I customers are equally well-equipped and educated to manage their commodity costs in an hourly LMP default service environment. Therefore, in the next round of default service plans that begin on June 1, 2015, we expect that EDCs will offer only hourly LMP to medium and large C&I customers with interval meters, subject to the several conditions discussed herein. Generally, this LMP product will be offered on a quarterly basis, with auctions for the entire LMP default service load in each EDC territory held in unison with auctions for residential and small C&I customers, as described in subsequent sections of this Order. Additionally, we will direct that the quarters synchronize with the PJM energy year starting on June 1 of each calendar year and ending May 31 of the following calendar year. As with current default service plans for large C&I accounts, wholesale energy suppliers participating in the auctions will bid on an administrative adder, with the generation component of the product being established by the hourly LMP.

As to the Industrials' proposal that hourly-priced services for large C&I customers be provided by the EDCs, the Commission prefers the model under which these services are auctioned to wholesale suppliers. Having the EDC providing these services and charging an administrative adder to large C&I customers entails a degree of involvement by the EDC that the Commission seeks to avoid with this group of customers in the robust competitive market we are seeking to promote. The Commission notes, however, that we are simply indicating that these services should be auctioned to other suppliers – not that they will necessarily be accepted. In a scenario where the auction results are not reasonable, the Commission retains the authority to reject them and direct the EDC to provide these services.

With respect to the frequency of the auctions, the Commission recognizes that the administrative adder is the only component on which the suppliers will be bidding since all other elements of the hourly product will be established by the market. Further, the Commission is cognizant of the concern raised by PPL that quarterly LMP product auctions may be hindered by potential administrative burdens. However, we do not have enough evidence within this proceeding to make a decision on which option, annual or quarterly auctions, is most prudent. Consequently, we will defer this decision until further evidence is provided within the EDCs' default service proceedings. We will note that, whichever option is chosen, the auction or auctions are to be held in unison with the residential and small C&I auctions, as specified in subsequent sections of this Order.

Regarding the Industrials' proposal for a failsafe mechanism in place to address the possibility of market failure, the Commission agrees. With only an hourly-priced default service option, most customers will shop to avoid the variability. As a result, if EGSs are not meeting the needs of large and medium C&I customers, we expect the Commission will have sufficient flexibility and a willingness to step in and revise the default service paradigm.

With respect to the use of load profiles to bill hourly LMP to customers who do not have interval meters, the Commission is persuaded by the parties opposing the use of this approach. While the Commission desires to expand the pool of large and medium C&I customers who receive hourly LMP services from the EDCs, the Commission understands the need to limit these services to those customers who have interval meters.

Specifically, the Commission agrees with PPL's comments regarding the difficulty of establishing a representative load profile for such a diverse group of customers which might, as a result of shopping, change character from time-to-time. Also, the Commission concurs with FE's observation that customers might become frustrated if they are billed at the hourly LMP on the basis of load profiles but cannot avoid high LMP prices through load-shedding measures. In addition, the Commission recognizes the challenges raised by PECO associated with reconciliation of real-time load obligations and load profiles in the absence of interval meters. Further, the Commission notes FE's comments regarding the need to program its billing system to accommodate the use of load profiles. Finally, although we realize that an accelerated or expanded deployment of interval meters and smart meter capabilities would enable EDCs to offer hourly LMP services to a larger number of large and medium C&I customers, we are not inclined to address those deployment schedules here since they are being, or have been, addressed in other proceedings.

As to the proposed delineation point of above 100 kW of demand, the Commission acknowledges that the more compelling point of delineation is whether the customer has an interval meter, as no EDC suggested any difficulty creating a subclass for default service. Therefore, at this time, the Commission continues to support the threshold of 100 kW for purposes of determining medium and large C&I customers, but expects EDCs to offer hourly LMP products only to the customers above that demand level who have interval meters. We expect the EDCs to continue adding medium C&I customers to the hourly LMP product as interval meters are deployed. Further, the Commission directs all LMP default service customers to be grouped into one single auction class for each EDC in order to avoid creating extremely small procurement classes. Lastly, the Commission agrees with the Industrials that the default service charges for capacity and transmission should be allocated, collected and reconciled for all hourly-priced customers in accordance with PJM rates and rate design for each product, and therefore directs such.

As to the Industrials' comments regarding the need to avoid cost shifting among medium and large C&I customers, since the Commission is neither directing the acceleration of smart meter deployment nor the application of load profile LMP billing, we believe any concerns about cross-subsidies are largely mitigated. Any potential new costs that may arise from expanding LMP billing for default service customers with smart meters and demand greater than 100 kW can be addressed in future default service proceedings.

Regarding the concerns presented by Pike, the Commission maintains its position that the changes included within this end state model should be applicable to all jurisdictional EDCs. The Commission appreciates that Pike's current default service product for all customers is based on spot market prices, which is consistent with our overall objectives. However, the Commission does not presently know what product will be proposed and approved in Pike's next default service plan proceeding. Therefore, it would be premature to exempt Pike, at this time. However, as noted previously, a smaller EDC is not precluded from submitting, for the Commission's review, a petition which provides evidence as to why it may not be appropriate, beneficial to customers or feasible to implement this model or certain specifics of this model in its service territory.

2. Residential and Small Commercial and Industrial Rate Classes

In its *Tentative Order*, the Commission proposed that EDCs offer quarterly PTCs that are synchronized with the PJM energy year for residential and small C&I rate classes. Further, we proposed that the PTC be established by procuring 100% of each EDC's default service load for each quarter one or two months in advance of the applicable quarter. We also proposed that the EDCs procure only full requirements products and that the EDCs continue to provide PTC estimates until the exact tariffed rate is established. *Tentative Order* at 17-18.

a. Comments

PPL, ConEd, WGES, PECO and NRG generally support the Commission's proposal to have EDCs offer a quarterly PTC based entirely on three-month, full requirements contracts procured in a single auction prior to each quarter. PPL submits that such a product will be more reflective of current market conditions than default products currently offered. PPL also states that reforming default service to offer this type of product to residential and small commercial customers is a logical step in the evolution of the marketplace. PPL at 14.

WGES states that the structure of default service is a major factor considered by EGSs when entering a retail market. WGES submits that the PTC should reflect prevailing market prices. In support, WGES contends that generation supply markets have been generally flat since the recession in 2008. Consequently, the presently-blended default service prices have given EGSs a window of opportunity to enter the market. However, WGES contends that if the generation market price trajectory moves upward, the blended default service contracts could establish a PTC that reflects previously lower prices and therefore forces EGSs to leave the market as they could not compete with the regulated default service price. Further, WGES submits that this scenario would send the wrong price signal to customers. WGES believes that this problem can be resolved by eliminating long-term contracts for default service supply, as the Commission has proposed. WGES at 2.

PPL and PECO also submit that auctions pursuant to the Commission's proposed default service products should be coordinated statewide for all EDCs. PPL contends that, since the product and procurement timing will be standard throughout the state, the Commission should consider introducing a common supply auction similar to the Basic Generation Service auction employed in New Jersey. PPL believes this may ensure the success of procurements in each EDC's service territory and could be a precursor to having DSPs that are not incumbent EDCs. PPL at 14.

PECO asks the Commission to establish a collaborative stakeholder process in the RMI proceeding to develop a uniform procurement process for all EDCs along with uniform supply master agreements (SMAs). PECO proposes to have the procurement process and SMAs approved by the Commission no later than June 1, 2014. In support of the coordinated procurement approach, PECO contends that the Commission's proposal may create significant resource and timing challenges for wholesale energy suppliers to participate in each quarterly auction for each EDC. Consequently, some wholesalers may choose not to participate in certain EDC auctions. These challenges will be compounded if EDCs decide to use different procurement strategies, such as declining clock or requests for proposals (RFPs), along with different SMAs. PECO submits that using a single, coordinated uniform procurement throughout the state will manifest significant administrative savings for EDCs and wholesalers which, in turn, may be reflected in wholesalers' bids. PECO notes that products and tranches would remain specific to each EDC. PECO at 8-10.

PECO states that the specifics of the uniform procurement and SMAs should be developed in the stakeholder group. However, PECO suggests that the Commission recommend some overarching design requirements and goals to guide the stakeholder proceeding. Specifically, PECO submits that a uniform statewide procurement process include the following features: (1) a standard certification process for each procurement year; (2) an end-of-day bid submission with notification that same evening; (3) a proportional assignment of time of use (TOU) load; (4) the exclusion of load tranches from existing block contracts that carry into the next round of default service; and (5) an established stakeholder process for continued improvement. PECO at 8-10.

RESA supports the Commission's stated goal to create a more market-based PTC. RESA believes that default service rates must be market-responsive and must reflect all costs related to default service so that competitive retail suppliers can compete on an equal footing with the EDC's default service. As such, RESA generally supports the Commission's proposed residential and small C&I product structure. However, RESA submits that the PTC for upcoming quarters should be provided to EGSs as soon as possible. RESA states that providing the final PTC calculation in a reasonable amount of time in advance of its effective date is important to provide both customers and EGSs time to react to the new PTC price signal. Consequently, RESA proposes that default service procurements be held 60 days in advance of upcoming quarters in order enable EDCs to calculate the new PTC no later than 45 days in advance of its effective date. RESA at 10.

PEMC cautiously supports the Commission's proposal, as it believes the proposal represents a marginal improvement over the current approach to procuring default service supply. However, PEMC submits that, if the PTC continues as the Commission proposes, including unbundled commodity costs or the introduction of a premium in this price is vital to give customers an apples-to-apples comparison with supply offers. PEMC at 6.

OCA and PULP submit that the Commission's proposed residential and small C&I default service product would not improve the competitive retail market, nor would it be in the best interest of residential customers. Both parties state that the Commission's proposal will cause customers to experience price volatility. According to these parties, this volatility will likely expose customers to seasonally high bills in the peak electric usage months of the summer. OCA and PULP contend that this exposure may compromise customers' ability to pay their electric bills, particularly those customers who have a lower income, may be older in age, or who may be victims of domestic violence. PULP also submits that the potential for higher summer bills can potentially result in an increase in utility disconnects which, in turn, can lead to potential dangerous health conditions such as fires and carbon monoxide poisoning from the use of unsafe heating sources. OCA at 10; PULP at 11-16.

OCA and PULP also contend that budget billing may not be a viable option for customers to avoid seasonally high bills. OCA states that, under the Commission's proposal, EDCs may face difficulty in estimating the annual generation costs of each customer when the default service supply and, consequently, the PTC is re-established every three months. In support, OCA states that there could be large true-ups needed in the budget billing process if the estimates of quarterly purchase prices in the future are inaccurate. OCA asserts that such a scenario may eliminate the usefulness of budget billing. OCA at 11.

OCA contends further that the volatility of the Commission's proposed product structure will be a detriment to customer choice because customers will only be able to determine if EGS offers are in their best interest for a three-month period. The potential for customers to enter into a contract with an EGS that may quickly move above the renewed PTC may depress, rather than foster, customer switching. Further, OCA submits that the price volatility inherent in the PTC under the Commission's proposal will make it more difficult for EGSs to plan their pricing and purchasing as their own customer loads may become less predictable as the PTC changes. Competitive EGS offers in the summer may be non-competitive in the shoulder or off-peak seasons. Customers may therefore switch to an EGS during the summer and revert to default service in the shoulder seasons. OCA concludes that this scenario might result in the very type of "boom/bust cycle" that the Commission is seeking to avoid. OCA at 12.

OCA further contends that the Commission's platform that longer-term contracts somehow bear less of a resemblance to current market conditions than shorter-term contracts is incorrect. OCA believes that the EDCs' present strategy keeps the default service price current through the wholesale market auctions and RFPs which procure contracts of various lengths which, when blended to formulate a PTC, create a less volatile market-based price. PULP echoes these sentiments. OCA at 12; PULP at 6 and 7.

OCA states that the default service product should be designed to be a stable product acquired through a mix of resources, with different contract delivery periods, from the competitive wholesale markets. In conclusion, OCA avers that limiting default service to a single, short-term product is not in the best interest of customers and will not support sustained, robust competition. OCA comments at 13-14.

Similarly, DLC submits that it is concerned that the sole use of three month procurements for residential and small C&I customers will produce unnecessary volatility in default service rates due to changes in seasonal demand and due to the potential for a dislocation in the wholesale energy market at the time of procurement. DLC avers that these forms of volatility are not the type that would lead to the "boom/bust cycles" about which the Commission is most concerned. Rather, a long-term rise in prices mixed with procurements years in advance of the delivery period is more likely to result in default service prices that are below current market prices. Therefore, DLC submits that a one-year default service rate procured no more than six months prior to the commencement of the delivery period is a better approach. DLC believes this approach provides reasonably contemporaneous pricing while avoiding concerns about volatility. DLC at 3.

DLC contends that the best inducement for shopping is long-term savings. DLC believes the volatility inherent in the Commission's proposal will lead to customer dissatisfaction if the PTC drops significantly after a customer enrolls with an EGS for a long-term product. Therefore, DLC opines that the Commission's proposal will not enhance shopping by residential and small C&I customers. DLC concludes that, whatever procurement period and structure is employed for residential and small C&I customers, the Commission should implement procurements of contracts at different times for each PTC period in order to dampen the effect of market dislocations at the time of a single procurement. However, DLC clarifies that it does fully support the elimination of laddering any contracts over various PTC periods in order to reduce over- and under-collections. DLC at 4.

EGSP contends that the Commission's proposed residential and small C&I product will do nothing to lower barriers to market entry for EGSs. EGSP submits that this proposal fails to remedy the inequities of current default service and the resulting anti-competitive effect. EGSP avers that implementing an annual procurement with annual price changes will produce better results for EGSs. In support, EGSP explains that an annual procurement of fixed-price products will eliminate the odd variability of quarterly prices and reconciliation. Further, EGSP states that an annual model would provide customers with greater price stability, which would be more comparable to typical EGS offers and would match market prices more closely than the present default service model while avoiding unnecessary volatility. EGSP at 7 and 8.

EGSP opines that the Commission's proposal will most likely lead to a scenario in which only those entities that own or control significant generation assets will be able to manage the risks of offering longer-term fixed priced products to customers. Instead, most EGSs will only be able to offer customers shorter-term prices, which may or may not compete with the PTC. EGSP believes this construct will increase the frequency of "boom/bust cycles" which, in turn, may drive customers back to default service for longer periods of time, if not permanently. EGSP at 7 and 8.

Citizen Power submits that semi-annual auctions should be used instead of quarterly auctions. In support, Citizen Power states that semi-annual auctions offer more stable prices for default service customers which, in turn, can provide more budget stability for said customers. Citizen Power also states that semi-annual auctions provide a less frequently changing PTC for customers who wish to shop. Citizen Power explains further that the disadvantage to its semi-annual auction proposal is that it provides a greater chance for the PTC to diverge from market prices. However, Citizen Power contends that large price swings in the electric market are not commonplace occurrences. Further, if a large price swing occurred, it would only affect the marketplace for a maximum of six months. Last, if the market price drops, customers will have an opportunity to receive service from an EGS at a more competitive rate. In summary, Citizen Power submits that it is unlikely that an EGS would choose not to participate in a market based on the small chance that the PTC will be below the market price for short period of time. Citizen Power at 2 and 3.

Citizens' and Wellsboro submit that they have a single default service product for all customers and therefore oppose splitting the default service product into two categories based on customer class. Citizens' and Wellsboro state that they are concerned that segregating customers into separate procurement groups, as proposed by the Commission, may diminish the attractiveness of the wholesale supply product to suppliers. Specifically, Citizens' and Wellsboro state that the total combined load of all customers is just over 50 megawatts (MWs). Citizens' and Wellsboro submit that, while it may be possible to conduct a quarterly, full requirements solicitation for a single tranche for each service territory, the Commission should consider the possibility that no suppliers will be interested in the territory and should develop a contingency plan prior to making a decision to include the companies in the new approach. Citizens' and Wellsboro at 5 and 6.

Citizens' and Wellsboro also contend that the Commission's proposal for residential and small C&I customers may not address the over- and under-collection issue. The two EDCs submit that full requirements tranches are delivered on a calendar quarter basis. Since customers' billing cycles often do not synchronize with the beginning of the month, generation bills will need to be pro-rated resulting in over- and under-collections. Citizens' and Wellsboro ask that the Commission explore whether wholesale suppliers could take on this collection risk associated with the proposed full requirements, load-serving contracts to alleviate the burden on small EDCs. Citizens' and Wellsboro at 6.

Lastly, Citizens' and Wellsboro state that implementing the Commission's proposal will require them to upgrade their information systems to facilitate additional electronic interactions with both retail and wholesale suppliers. Citizens' and Wellsboro are also exploring the use of a third-party vendor to provide Electronic Data Interchange (EDI) services. As such, Citizens' and Wellsboro state that the Commission should confirm that they will be entitled to full and timely recovery of costs to implement EDI, billing system changes and other activities related to implementation of customer choice from EGSs and/or in a non-bypassable generation rider. Citizens' and Wellsboro at 7.

Pike seeks to be exempted from the Commission's proposal regarding the default service product as it already provides default service at spot market prices and will continue to do so under its approved plan for the period from June 1, 2012 through May 31, 2014. Noting that this approach is wholly consistent with the Commission's stated goal of creating EDC default service products that are more market-based, Pike also refers to difficulties it would have in conducting quarterly auctions for its supply since it would have to negotiate and enter into a contract with a merchant generator and pay an unjustified premium given the small amount of default service load to be served. Pike at 6 and 7.

b. Resolution

The Commission agrees with the numerous parties who generally support the proposed residential and small C&I product. Consistent with the positions detailed in the *Tentative Order*, along with the support presented in the comments by parties such as PPL, ConEd, PECO, WGES and NRG, we agree that the product, as proposed, will reduce the likelihood of over- and under-collections and foster a PTC that more closely tracks current market conditions.

As discussed in a subsequent section of this Order, the Commission believes a change to the existing statutory procurement standard may be required to use a 90-day default service product for residential and small C&I customers. Should legislative efforts fall short, we will consider an alternative shorter-term product that is more reflective of market conditions than the currently-offered default service products. If such legislative changes are effectuated, the Commission expects the EDCs to offer a 90-day product, as described above, to residential and small C&I customers. This product would be included in the next round of default service plans, which take effect on June 1, 2015.

Additionally, the Commission agrees with RESA's timeline concerns. The Commission believes that establishing the exact PTC no less than 45 days prior to its effective date will be beneficial for consumers and EGSs for shopping and marketing, respectively. Consequently, we direct that the EDC auctions be held far enough in advance to permit EDCs to establish a final PTC no less than 45 days prior to the effective date of the PTC.

Further, the Commission agrees with PECO and PPL's recommendation to collaborate all EDC auctions in order to realize efficiencies and reduce expenses. As such, we direct all EDCs to hold collaborative quarterly auctions. In order to develop the details required to collaborate quarterly auctions, and consistent with the comments provided by PECO, we direct OCMO to form a Procurement Collaboration Working Group. The end goals of this Group will be to formulate a uniform yearly certification process, a uniform supply master agreement, and a procurement methodology/timeline. We further direct the Procurement Collaboration Working Group to develop any other necessary protocols, procedures, or documents required to run an auction every quarter which procures default service load for each EDC through a single, third-party consultant. We specifically note that individual EDC load will not be aggregated, but rather separate auctions for each service territory will be held in a parallel process, which will be monitored and managed by a single third party consultant. Further, we agree with PECO's recommended timeline for the working group process, and therefore direct that the Procurement Collaboration Working Group submit its recommendations to the Commission as soon as practicable, but no later than April 1, 2014, in order to provide the Commission time to approve or amend the recommendations by June 1, 2014. Finally, we note that the group need not reach consensus as long as the views of all parties are documented in its submittal to the Commission.

As to OCA's concern about the effectiveness of budget billing under the proposed default service product construct, we note that this topic is addressed in the Consumer Protections section of this Order.

Concerning Citizens' and Wellsboro interest in obtaining Commission approval for cost recovery associated with upgrades to its systems necessary to accommodate our directives, the Commission will not make any affirmative declaration of cost recovery within the scope of this proceeding. Any such cost recovery should be sought by

Citizens' and Wellsboro through a proceeding that specifically addresses the prudency and necessity for specific incurred costs.

As with the default service product for medium and large C&I customers, the changes included within this end state model will be applicable to all jurisdictional EDCs. The Commission appreciates that Pike's current default service product for all customers is based on spot market prices, which is consistent with our overall objectives. However, the Commission does not presently know what product will be proposed and approved in Pike's next default service plan proceeding. Therefore, it would be premature to exempt Pike, at this time. As noted previously, a smaller EDC is not precluded from submitting, for the Commission's review, a petition which provides evidence as to why it may not be appropriate, beneficial to customers or feasible to implement this model or certain specifics of this model in its service territory.

3. Legislative Changes

In the *Tentative Order*, the Commission recognized that many of the proposals may require changes to existing legislation and Commission regulations. The proposed changes to the default service product are among those that the Commission intends to pursue with the General Assembly. *Tentative Order* at 18.

a. Comments

While many commenters acknowledge or agree with the need for legislation to change the default service products in the manner proposed by the Commission, RESA submits that the proposed procurement approach is consistent with the existing law. RESA maintains that the law does not require a specific rate design methodology for default service. Rather, RESA explains that the law requires the DSP to offer electric generation service pursuant to a Commission-approved default service plan that must include a "prudent mix" of resources designed to provide adequate and reliable service, provide the least cost over time and to achieve those results through competitive processes that include one or more of the following: auctions, RFPs and/or bilateral agreements. RESA notes that the Commission has determined that what constitutes a prudent mix should be interpreted in a flexible fashion to permit DSPs to design their own combination of products to meet the requirements of the statute.

In support of its view that the Commission does not need legislative changes to pursue the changes to the default service product proposed in the *Tentative Order*, RESA refers to Commission decisions addressing default service plans filed by Pike that have approved spot-market-only approaches for all customers. In addition, RESA emphasizes that the Commission has approved hourly prices for large C&I customers in several service territories. RESA at 11-13.

b. Resolution

Section 2807(e)(3.1) of the Code, 66 Pa. C.S. § 2807(e)(3.1), which was added to Chapter 28 of the Code by Act 129, obligates EDCs to procure electricity through competitive procurement processes that include one of the following: (i) auctions; (ii) requests for proposals; and (iii) bilateral agreements. Section 2807(e)(3.2) of the Code, 66 Pa. C.S. § 2807(e)(3.2), further provides that the purchased power must include a "prudent mix" of spot market purchases, short-term contracts and long-term purchase contracts. According to Section 2807(e)(3.3) of the Code, 66 Pa. C.S. § 2807(e)(3.3), the prudent mix of contracts shall be designed to ensure adequate and reliable service and the least cost to customers over time.

As noted by RESA, the Commission has found in Pike's default service plan proceedings that the "prudent mix" standard may be fulfilled by only one product – a spot market product in Pike's case – when it is the option that is most likely to produce the least cost over time and the benefits provided by the other products are not commensurate with their costs. While this finding originally occurred in 2007, prior to the passage of Act 129,[14] the Commission has reached the same decision in 2009 and 2012.[15] It is important to note that, before reaching those decisions, the Commission considered a variety of factors that were unique to Pike. Most recently, those factors included Pike's extremely small customer base and the fact that 73% of customers are served by EGSs, leaving only 1300 customers on default service. Finding that the spot market approach complies with the law under those circumstances, the Commission concluded that requiring Pike to follow a procurement approach that includes hedging would produce an unreasonable result: namely, higher prices with little or no customer benefits. Similar rationales have applied to the approval of hourly LMP for large C&I customers.

While the Commission is steadfast in its view that our decisions to permit spot market approaches in specific situations are appropriate, we are concerned that a general pronouncement directing a 90-day product for residential and small business customers and an hourly LMP product for "medium" C&I customers may raise legal questions about compliance with the above-referenced provisions of the Competition Act. To avoid any legal uncertainty,[16] the Commission would prefer to pursue legislative amendments that clearly provide the authority to approve default service plans containing products that more closely resemble current market conditions at the time of delivery. Further, as a creature of the Legislature, the Commission is well-served to ensure that the General Assembly is supportive of our overall policy direction on matters as important as the retail market for electricity. Although the Commission appears currently to have

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[14] *Petition of Pike County Light & Power Company for Expedited Approval of its Default Service Implementation Plan*, Docket No. P-00072245 (Opinion and Order entered August 16, 2007).

[15] *Petition of Pike County Light & Power Company for Expedited Approval of its Default Service Implementation Plan*, Docket No P-2008-2044561 (Opinion and Order entered March 23, 2009); *Petition of Pike County Light & Power Company for Approval of its Default Service Implementation Plan*, Docket No. P-2011-2252042 (Opinion and Order entered February 25, 2011).

[16] The most recent Pike decision is on appeal at the Commonwealth Court, in *Irwin A. Popowsky v. Pennsylvania Public Utility Commission*, Commonwealth Court Docket No. 1179 C.D. 2012.

authority to establish shorter-term default service products that are more reflective of market conditions than existing products, our intention is to seek legislative changes that afford the Commission as much flexibility as possible going forward so that we can quickly adapt our policies as necessary to meet the needs of the competitive market and consumers.

E. Transition Timeline

In the *Tentative Order*, the Commission proposed June 1, 2015, as the effective date for changes to the default service product offered by the EDCs, noting that existing and pending default service plans are scheduled to terminate on May 31, 2015. With that implementation date in mind, the Commission stated in the *Tentative Order* that we would encourage the passage of any necessary legislative changes in 2013. *Tentative Order* at 18.

Further, since the Commission expects the next phase of default service plans to be significantly more streamlined than has been the case under Section 2807(e)(3.6), 66 Pa. C.S. § 2807(e)(3.6), we proposed to issue an order containing filing guidelines as soon as practicable after the passage of legislation to set forth the components that should be included in the default service plans and any other implementation issues. To ensure that EDCs have sufficient time to implement the next round of default service plans, the Commission proposed to require them to be filed by July 1, 2014, for approval within six months. *Tentative Order* at 18.

1. Comments

Several parties support June 1, 2015, as the implementation date for the new default service products. FE characterizes the Commission's proposal as a logical timeline for a seamless transition, given the expiration of default service plans on May

31, 2015. FE at 5 and 6. PPL notes that its default service plan for the period ending May 31, 2015, contains a procurement schedule under which all supply contracts will expire by that date, so that a relatively clean transition is possible on June 1, 2015. PPL at 15 and 16. PEMC calls the timeline reasonable and likely achievable. PEMC at 6.

OCA agrees that no changes to default service should be implemented before June 1, 2015. However, it urges the Commission to forego establishing a timeline for implementation until the General Assembly determines whether it will enact any changes. OCA at 14 and 15.

RESA generally supports the Commission's timing proposal but is concerned about delays that may result from pursuing what it believes are potentially unnecessary legislative changes. Therefore, RESA urges the Commission to avoid letting the pursuit of unnecessary legislative changes slow the progress toward the June 1, 2015 goal. RESA at 11-13.

Some parties raise concerns about the Commission's proposal to shorten the review period to six months for the next round of default service plans, noting that the Commission's regulations provide for a nine-month review period, which is consistent with the Competition Act. OCA submits that the nine-month timeframe is reasonable and should be maintained, contending that shortening it to a six-month period would make it increasingly difficult to fully examine each EDC's plan. OCA also suggests that a six-month timeframe may not allow sufficient lead time for plan corrections, auctions or RFPs. OCA at 14 and 15. PECO shares similar concerns, noting that six months may be insufficient time to review the first default service plan under a new legislative and regulatory framework. PECO therefore recommends that the Commission maintain the nine-month time period between filing and approval of the first round of default service plans after the changes but retain flexibility to implement a shorter review time for future plans. PECO at 12 and 13.

NRG urges the Commission to establish a timeline for post-2015 when the default service products proposed in the *Tentative Order* will be transitioned to EGSs and then subsequently eliminated at a later date after transition to EGSs. Specifically, NRG suggests that the date for this transition to EGS-provided default service should be no later than June 1, 2016. NRG at 4-7. RESA offers a similar comment, describing the Commission's goal of a more market-based PTC as a good step forward in the transition to an optimal end state where a fully robust competitive market exists. RESA at 11-13.

2. Resolution

The Commission believes that it is appropriate to establish June 1, 2015, as the implementation date for the new default service model, with the understanding that any necessary legislative changes need to be made in 2013. Not only does June 1, 2015, correspond to the expiration of the EDCs' default service plans, we believe it is critical to implement changes designed to improve the sustainability of the market while wholesale market prices are stable. Declining to establish an implementation date by this Final Order, as suggested by OCA, would add even more uncertainty in the marketplace and potentially discourage EGSs from continuing or commencing retail activities.

While the Commission appreciates RESA's concern about the potential for legislative changes to delay our progress toward this goal, we have expressed our views above for why we consider it prudent to pursue those amendments. Further, the Commission has indicated that we are prepared to devote the resources necessary to implement changes that we believe are essential to the proper functioning of the competitive market for electricity.

As to NRG's suggestion that the Commission establish a timeline for post-2015 for transitioning EGSs into the default service role, we believe it is premature to do so at this time. Going forward, we plan to carefully monitor developments in the competitive market and will not hesitate to revisit the default service model in the future, if necessary.

With respect to the Commission's proposal for a six-month timeframe for approving default service plans that go into effect on June 1, 2015, the Commission understands the concerns raised by the parties about the challenges of fully reviewing the plans, especially since they will be the first round of plans under a new legislative and regulatory framework. Therefore, the Commission will refrain at this time from establishing a review period and instead will do so when we issue an order implementing new legislation. To the extent the Commission can maintain the nine-month review period or a longer period of time than six months and still meet the June 1, 2015 implementation date, we intend to do so.

F. Consumer Protections

The Competition Act requires that EDCs maintain, at a minimum, the levels of customer service and protections that were in existence prior to the effective date of the Act. 66 Pa. C.S. § 2807. In response to these legislative directives, the Commission promulgated regulations to ensure the continued provision of high-quality customer service, including:

- **Customer Information** (52 Pa. Code §§ 54.1 – 9). This ensures that customers have the information they need to make informed decisions while participating in the competitive market, including rules governing billing information and format, and marketing activities. This includes a rule stipulating that advertised prices must equal the price the customer is billed. Also included are detailed supplier disclosure (contract) requirements that directs a supplier to put into writing terms and conditions including pricing information, length of agreement, cancellation provisions, penalties, and any bonuses or incentives. The contract must also include a three-day right of rescission, under which the customer can cancel the contract without penalty within three days of receiving the contract.

- **Reporting Requirements for Quality of Service Benchmarks and Standards** (52 Pa. Code §§ 54.151-156). These rules allow the Commission and the public to monitor various customer service metrics to help ensure that distribution utilities continue to maintain quality service to customers. This includes call center and field personnel performance, metering, billing, dispute handling and surveys of customer satisfaction. The Commission compiles and presents this information in an annual report that is available on the Commission's website.[17]
- **Universal Service and Energy Conservation Reporting Requirements.** (52 Pa. Code §§ 54.71 – 78). These rules assist the monitoring of the utility collection's performance and helps to ensure that universal service and customer assistance needs are being addressed. This includes information on the number of customers participating in universal service programs and the costs of the programs. This information is compiled and presented in an annual report that is available on the Commission's website.[18]
- **Standards for Changing a Customer's Electricity Generation Supplier.** (52 Pa. Code §§ 57.171 – 179). These regulations put in place procedures suppliers and utilities are to follow to change a customer's supplier of choice. These rules are also intended to ensure that a customer's generation supply is not switched without the customer's authorization. The Commission has directed staff to initiate a rulemaking to revise these regulations, with the intent of accelerating the switching process. This review will include the possibility of revising the regulations in recognition of new capabilities resulting from the implementation of

[17] These reports are available at the following link: http://www.puc.pa.gov/filing_resources/customer_service_performance_reports.aspx.
[18] These reports are available at the following link: http://www.puc.pa.gov/filing_resources/universal_service_reports.aspx.

advanced metering technologies. This initiative is discussed in more detail later in this Order.

- **Marketing and Sales Practices for the Retail Residential Energy Market.** (52 Pa. Code §§ 111.1 – 14). These pending regulations are intended to ensure that consumers receive the information they need from sales agents to make informed decisions about their energy choices. They are also intended to help protect public safety as it relates to door-to-door sales and marketing activities. Suppliers will be expected to obtain background checks on all door-to-door agents. In order to guard against misrepresentation or intimidation by the sales agent, the rules require that all door-to-door and telephone sales transactions are to be verified by a process separate from the sales process and agent. The rules also specify the information a sales agent should provide a potential customer to permit the customer to make informed energy choices.
- **Standards and Billing Practices for Residential Utility Service.** (52 Pa. Code §§ 56.1 – 231). Going back to the *Customer Services Order of 1997*,[19] the Commission has required compliance with Chapter 56. Section (I)(A) of these Guidelines requires that "Electric Distribution Companies (EDC), Generation Suppliers, Brokers, Marketers and Aggregators must abide by the Standards and Billing Practices for Residential Utility Service at 52 Pa. Code, Chapter 56" and Section (L)(2) of the Guidelines requires that a supplier of last resort (DSP) "must continue to apply the Chapter 56 termination provisions for nonpayment, including negotiation of payment agreements based on a consideration of certain factors such as the ability of the ratepayer to pay." These guidelines rest on Section 2809(e) of the Competition Act, which explicitly directs the Commission to "impose requirements necessary to ensure that the present quality of service provided by electric utilities does not deteriorate, including assuring that adequate

[19] *See Guidelines for Maintaining Customer Services at the Same Level of Quality Pursuant to 66 Pa. C.S. § 2807(D), and Assuring Conformance with 52 Pa. Code Chapter 56 Pursuant to 66 Pa. C.S. § 2809(E) and (F),* Docket No. M-00960890F0011 (Order adopted July 10, 1997).

reserve margins of electric supply are maintained and assuring that 52 Pa. Code Ch. 56 (relating to standards and billing practices for residential utility service) are maintained." Chapter 56 standards address billing, payment, applications and credit, security deposits, termination, and dispute handling.

The default service model that was proposed in the *Tentative Order* requires no revisions to any of the consumer protections noted above, and we proposed that the protections that electric consumers have come to expect remain intact and fully in effect. We also noted that this does not preclude the Commission from considering or revising any of the above-noted regulations. However, any revision of these regulations will always be in the context of our statutory charge found in Section 2807 of the Competition Act – that the quality of the service provided does not deteriorate. Any such revision will result, at a minimum, in the maintenance of the current level of service or serve to enhance it.

1. Comments

The parties generally agree with the Commission's proposal and agree that there is no need to change current consumer protection regulations to accommodate the default service model being proposed by the Commission. No party expresses a desire to extensively modify or eliminate any of the current regulations.

PPL took issue with the Commission's linking of preserving consumer protection rules with the role of the EDC as a DSP, in part, because some of the consumer protections have nothing to do with the provision of default service. PPL at 17. However, OCA believes that the EDC's expertise in complying with these regulations is an argument for retaining them in the DSP role. OCA at 15 and 16. PPL, along with PULP and PCADV also question the sustainability and effectiveness of Chapter 56 residential regulations governing billing, payment, termination, disputes and related matters in a Supplier Consolidated Billing (SCB) environment. These parties question the ability of the Commission to enforce the regulations in an environment where numerous suppliers may be providing SCB. PPL at 19; PCADV at 3 and 4; PULP at 19.

PCADV doubts the Commission can apply any Chapter 56 regulations to EGSs, given that the Commission has only issued guidelines in this respect; guidelines that are not enforceable as regulations. PCADV at 4. PCADV is also troubled by the Commission's explicit reservation of its right to revise any or all consumer protection regulations. This, along with "the Commission's failure to specify the specific legislative changes it intends to seek" causes PCADV to question the Commission's future intentions with respect to Chapter 56. PCADV at 5.

OCA and PULP question the effectiveness of the budget billing regulations in Chapter 56 in a new default service environment. These parties believe that the price of default service obtained on a quarterly basis will be difficult to estimate in advance – thereby complicating the calculation of budget billing amounts for individual consumers. OCA at 11; PULP at 16.

2. Resolution

Given the widespread support among the parties, the Commission will maintain our original proposal to preserve existing consumer protection rules. No party argued or made a case for any significant revision of the current regulations. However, we do want to address the concerns and questions raised by some of the parties.

We believe PCADV's concerns about the ability of the Commission to impose Chapter 56 standards upon suppliers are based on a misunderstanding. While the *Customer Services Order* PCADV cites is indeed a set of guidelines, this Order is not the foundation upon which the Commission's authority regarding Chapter 56 rests. As noted above, the Commission's authority in this regard is based on statute - Section 2809(e) of the Competition Act, 66 Pa. C.S. § 2809(e). Additionally, as part of the Commission's supplier licensing process, suppliers must complete an affidavit acknowledging that "it has a statutory obligation to conform with 66 Pa. C.S. §§ 506, 2807(D)(2), 2809(B) *and the standards and billing practices of 52 Pa. Code Chapter 56*" (emphasis added).[20] Given this strong foundation, the Commission is confident that it can indeed impose Chapter 56 obligations upon suppliers and has, in fact, done so and will continue to do so. As noted above, the Commission sees no need, and has no intent, to seek any legislative changes that would impact the consumer protections noted above, including Chapter 56. This includes any revision to our statutory charge found in Section 2807 of the Competition Act – that any revision to consumer protection regulations will either preserve or enhance the quality of the service provided.

As for PPL's objection to linking consumer protections to the EDC in the role of the DSP, we want to add that while we noted in the *Tentative Order* that many of these protections, especially Chapter 56, have traditionally been the obligation of the EDC, this was not intended to preclude a supplier from performing the role as a DSP. As we noted above, the Commission clearly has the authority to impose Chapter 56 requirements upon suppliers, and this would obviously be a qualifying standard any supplier would have to agree to before even being considered as a DSP. With regard to the concerns of PPL, PULP and PCADV about Chapter 56 compliance in the context of SCB, we will address those concerns later in this Order in our discussion of SCB.

We acknowledge the concerns of OCA and PULP with the viability of budget billing in the default service environment proposed by the Commission, but believe their concerns are overstated. Quarterly default service rates are not new; they have been

[20] This affidavit is Appendix B of the supplier application package and can be viewed on the Commission's website at: http://www.puc.state.pa.us/general/onlineforms/pdf/EGS_Licen_App.pdf

changing quarterly since 2010 and the utilities have been calculating budget amounts without apparent problems since then. Budget bill amounts (sometimes referred to as "equalized bills" or "average bills") are not calculated on an annual basis. In fact, the budget billing regulations at 52 Pa. Code § 56.12(7) require that they be reviewed "at least 3 times" during the budget billing period (a budget billing period being ten, 11 or 12 months). It is expected that, during these routine quarterly reviews, the utility will adjust the budget bill amount up or down to reflect usage and rate changes in order to prevent the accumulation of large over or under-collections. Should a large under-collection accumulate, this regulation was revised in 2011 to require that any large under-collection amount be amortized over the next six to 12 months.[21] Given these detailed requirements and protections in the budget billing regulations, the Commission is confident that consumers will continue to be able to utilize budget billing to obtain a more stable, average monthly bill, if they so prefer.

G. Portability of Benefits for Low-Income Customers

The Competition Act requires the Commission to maintain, at a minimum, the protections, policies and services that assist customers who are low income to afford electric service. 66 Pa. C.S. § 2802(10). That Act also requires the Commission to ensure that universal service and energy conservation policies are appropriately funded and available in each electric distribution territory. 66 Pa. C.S. § 2804(9). "Universal service" is generally defined as policies, protections and services that help low-income customers maintain electric service. 66 Pa. C.S. § 2803. Universal Service programs include Customer Assistance Programs (CAP), the Low Income Usage Reduction Program (LIURP), Customer Assistance and Referral and Evaluation Programs (CARES) and various utility hardship funds.

[21] This 2011 revision to 52 Pa. Code § 56.12(7) is an example of the Commission revising a consumer protection regulation in the context of Section 2807 of the Competition Act in that it served, in this case, to enhance the protections consumers receive.

CAP is a general term used to describe utility payment assistance and debt-forgiveness programs for payment-troubled households.[22] CAP's payment assistance feature is intended to provide affordable monthly bills based on a household's size and gross income. These lower rates are applied to ongoing usage as long as the household remains current and timely in paying its monthly customer assistance payments. CAP rates may take the form of a discounted price on actual usage, on either all or a portion of the usage, or a monthly amount that is calculated upon a percentage of the household income. CAP programs are currently guided by the "Policy Statement on Customer Assistance Programs," 52 Pa Code §§ 69.261-69.267.

At the time the Tentative Order was issued, the ability of a CAP customer to participate in the competitive market varied by EDC. Some EDCs allowed shopping without restriction while other EDCs may have had rules restricting or even prohibiting a CAP customer from shopping. In the *Tentative Order*, we proposed that all EDCs, if they have not done so already, develop plans that allow their CAP customers, on or before January 1, 2015, to shop in the competitive market without restriction. *Tentative Order* at 23.

LIURP is a statewide, utility-sponsored, residential usage reduction program mandated by Commission regulations. *See,* 52 Pa. Code §§ 58.1-58.18. The primary goal of LIURP is to assist low-income residential customers to conserve energy and, as a result, reduce energy bills. Hardship funds are programs that provide cash grants to qualifying households to assist in the payment of utility bills. They are funded through contributions made by the public and utility shareholders and employees. CARES is a

[22] 52 Pa. Code § 54.72 – CAP – Customer Assistance Program – An alternative collection method that provides payment assistance to low-income, payment troubled utility customers. CAP participants agree to make regular monthly payments that may be for an amount that is less than the current bill in exchange for continued provision of electric utility services.

social service and referral program for households encountering some form of extenuating circumstance or emergency that results in the household's inability to pay for utility service. Qualifying households may receive counseling and/or direct referrals to community resources that can aid the family in resolving the emergency. A customer's eligibility or participation in LIURP, hardship funds or CARES is not affected by whether or not a customer shops. As such, in the *Tentative Order*, we proposed no changes to these three programs and proposed that they should remain a function of the utility for the foreseeable future.

The Low Income Heating Energy Assistance Program (LIHEAP) is often discussed in the context of universal service, but, in fact, is not a utility-funded or administered program. LIHEAP is funded by the federal government and is administered by the Pennsylvania Department of Public Welfare (DPW). As such, in the *Tentative Order*, recognizing that our influence over this program is very limited, we only proposed that the Commission work with DPW to explore what can be done to make suppliers eligible for LIHEAP payments - making these benefits more portable.

1. Comments

In general, consumer representatives express concerns about the participation of CAP customers in the competitive shopping market. OCA believes that if CAP customers are going to be permitted to shop, a model must be developed that allows the customer to retain their CAP benefits without increasing the cost to the customer or to the customers who must bear the costs of the program. OCA bases their concerns on data presented in the PPL default service proceeding that indicated that, of the 47% of PPL CAP customers shopping, 73% were paying more than if they had remained with PPL. OCA also suggests that the Commission allow interested parties to participate in the development of the EDC CAP portability filings "so that solutions to these issues can be developed." OCA at 16 and 17.

PULP believes that CAP customer participation in the competitive marketplace must be contingent on a variety of consumer protections provided on a uniform, statewide basis. These protections should include supplier prices that are always at or below the default price; cancellation without penalties at any time; exemption from security deposits; must be billed by a utility, not the supplier; specific consumer education efforts; full retention of all CAP program benefits and extended disclosure and rescission rights. PULP at 21 and 22. PULP believes these protections are needed due to the high degree of economic vulnerability and the need for rate stability and affordability for low-income households. PULP expresses concern about the potential economic harm of "unsuccessful shopping decisions or failure to maintain constant rate vigilance" to both the CAP customers and the non-CAP customers who subsidize CAP rates. PULP at 20. PULP also is concerned about the Commission's proposal to let each EDC develop a plan suitable for its service territory. PULP believes that this indicates that the Commission has failed to seriously confront the many significant issues involved and that the delegation of this responsibility is an abuse of discretion. PULP at 21. Citizen Power likewise believes that a statewide framework regarding what consumer protections are necessary should be developed. Citizen Power at 4.

PECO, an EDC whose CAP customers cannot currently shop, notes that it will need to spend significant amounts on programming, re-training and consumer education to implement CAP customer shopping. PECO at 14. Concerning consumer protections, PECO states that, if CAP customers pay generation prices higher than PECO default prices, it will erode some of the existing protections against price volatility that these customers have enjoyed and will adversely affect the affordability of their utility service. This could result in PECO increasing CAP benefits to return the customer to affordability and that these costs would increase the cost of the CAP program. PECO recommends that the Commission carefully balance affordability and cost containment principles in reviewing CAP shopping plans to maintain public support for those programs. PECO at 15.

PPL believes it would be inconsistent to prohibit customers with the greatest economic need from shopping for alternatives to default service and that there is no evidence to suggest that CAP customers do not have the capability to make shopping decisions, just like other customers. However, PPL notes that there are complexities that must be addressed, including "ineffective" shopping by CAP customers, which could mean paying more than the default rate, or not paying the lowest available price. This "ineffective shopping" could create a burden on the rest of the residential population that supports CAP financially. PPL at 21. Also, PPL notes that current policy at 52 Pa. Code § 69.265(3)(ii) prohibits CAP participants from subscribing to "non-basic services that would cause an increase in monthly billing and would not contribute to bill reduction." PPL questions the applicability of this policy in the context of EGS offers like gift cards, airline miles and other inducements. PPL at 21 and 22. PPL believes none of these complexities are insurmountable and are most logically addressed in the three-year universal service plans filed by each EDC. PPL also suggests that June 1, 2015, is a more appropriate effective date for any changes. PPL at 23.

FE notes that all of its Pennsylvania EDCs are already in compliance with the Commission's proposal in that all of their CAP customers can shop without restriction or loss of benefit. FE believes that a CAP customer that shops should receive the total result of their action, regardless of the magnitude of their EGS rate in comparison to the default service rate. That is, the customer should get the benefit or detriment of the difference between the PTC and the EGS price they receive. FE 6 and 7. FE further notes that a comparison of the EGS rate to the default rate at any one point in time does not take into consideration the value a CAP customer may place on other factors, such as long-term fixed EGS rates or other value-added products and services that may be offered by the EGS. FE at 7.

In general, the EGSs believe that CAP customers should be allowed to participate in the shopping market. RESA believes that CAP customers should preserve their benefits and not be denied the benefits available from the competitive market. RESA at 14. PEMC strongly supports the Commission's proposal, but emphasizes that care should be taken to educate and protect CAP customers in particular. PEMC at 7. NEM believes that CAP customers can receive a double benefit – the payment assistance garnered as a result of the CAP program, as well as potential energy commodity cost savings to be realized from shopping. NEM at 6. NEM adds that this double benefit is particularly significant because energy expenditures comprise a large portion of the budgets for low income consumers as compared to other households. NEM at 6 and 7. NRG opines that CAP benefits need to be fully portable to allow low income customers to exercise their right to shop for energy products that best meet their needs. NRG at 7. However, NRG encourages the Commission to require statewide uniformity in how this is accomplished in order to minimize customer confusion and to simplify the programs. NRG points to Texas as a state that successfully implemented an overhaul to its utility specific low-income customer assistance programs that now allows all customers to shop and retain their low income benefits through an easy-to-understand cents-per-kWh discount program. NRG recognizes that the significant systems improvements required to effectuate this change will require a concerted effort by all interested stakeholders. NRG at 8.

2. Resolution

Concerning CAP and our proposal that all EDCs, if they have not done so already, develop plans that allow their CAP customers to shop in the competitive market – we note that events have more or less taken over and have made our original proposal moot, for the most part. All of the major EDCs have reported that their CAP customers can shop, with the exception of PECO. In the case of PECO, the Commission has already provided direction in other forums – specifically PECO's default service plan[23] and pending CAP plan.[24] Also, see the January 3, 2013 *Secretarial Letter* where the Commission clarifies the timeframes and sequence of the PECO CAP plan proceeding in relation to the PECO CAP shopping plan – acknowledging that what occurs in the PECO CAP plan proceeding may impact the plans to allow PECO CAP customers to shop.[25] PECO has been directed to allow their CAP customers to shop by April 1, 2014, and has to develop and file a plan to facilitate this once their pending CAP plan is approved (it is expected that PECO will be filing a CAP shopping plan on or around May 1, 2013).

We continue to believe that one of the basic intents of the Competition Act – to "permit retail customers to obtain direct access to a competitive generation market" - was intended to include all customers. 66 Pa. C.S. § 2802(3). We agree with PPL that CAP customers have the capability to make shopping decisions and should be allowed to do so. As NEM points out, these customers can, in addition to their CAP benefit, also receive the additional benefit of possible energy costs savings. We agree with PEMC and PULP that care must be taken to educate CAP customers so that they understand how their CAP benefit interacts with shopping. EDCs should provide such information along with the information they routinely provide to CAP customers when explaining their CAP benefits.

The Commission acknowledges the concerns expressed by the parties about the complexities involved with the participation of CAP customers in the competitive market and the possible impact on these programs. However, we agree with FE that measuring

[23] *Petition of PECO Energy Company for Approval of its Default Service Plan*, Docket No. P-2012-2283641 (Order entered November 21, 2012).
[24] *PECO Energy Company Universal Service and Energy Conservation Plan for 2013-2015 Submitted in Compliance with 52 Pa. Code §§ 54.74 and 62.4*; Docket No. M-2012-2290911.
[25] Secretarial Letter re: *Petition of PECO Energy Company for Approval of its Default Service Program*; Docket No. P-2012-2283641; *PECO Energy Company Universal Service and Energy Conservation Plan for 2013-2015 Submitted in Compliance with 52 Pa. Code §§ 54.74 and 62.4*; Docket No. M-2012-2290911, dated January 3, 2013.

and determining the benefits of shopping requires more than just comparing a supplier price to the default price at one point in time. The Commission agrees with PPL that none of these complexities or concerns is insurmountable. In response to the concerns expressed by PULP and OCA that interested parties have a chance to participate in these matters, we note, as PPL does, that the major EDCs are required to file universal service plans with the Commission every three years. That review and approval process provides any interested party an opportunity to participate in the ongoing development of universal service programs. Regarding the development of these programs in the future, we do find merit in the ideas expressed by parties, including NRG and Citizen Power, that we should explore more comprehensive statewide solutions and structures. However, we think that a major undertaking like this is outside the scope of this proceeding and is best left to a future initiative.

Concerning LIURP, hardship funds and CARES, no parties' comments persuade us to revise our original proposal and thus we propose no changes to these three programs. They will remain a function of the utility for the foreseeable future. As for LIHEAP, as we noted in the *Tentative Order*, our influence over this program is very limited. Also, the portability of LIHEAP benefits only becomes an important issue if, at some point in the future, a supplier is moved into the DSP role. Given that we are, per this Order, keeping the EDC in the DSP role, this is not a critical matter at this time. However, if at some point it is proposed that a supplier move into the DSP role, the ability of suppliers to receive LIHEAP payments as vendors may need to be addressed.

H. Supplier Consolidated Billing

Supplier Consolidated Billing (SCB) is a billing option where the EGS bills the customer for both its EGS's generation charges *and* the EDC's distribution charges. Under SCB, the customer receives only one bill, from the EGS, and no longer receives a bill from the EDC. SCB was a billing option established by some of the EDCs' restructuring settlements in the 1990s, but was never utilized. However, some EGSs have expressed interest in resurrecting SCB, believing that it helps them establish a stronger EGS-customer relationship. SCB presents several technical and legal questions.

In April 2010, the Electronic Data Exchange Working Group (EDEWG) convened a working group to discuss SCB in the context of EDI requirements. In August 2010, this EDEWG-SCB working group issued a report that announced a consensus was reached on some issues, but that many issues remained unresolved and would have to be referred to OCMO and the Committee Handling Activities for Retail Growth in Electricity (CHARGE).

The issues identified during informal discussions by the above-mentioned groups included the following:

- What is the payment obligation of the EDC and EGS to each other?
- Which entity is responsible for providing regulatory inserts and information?
- Which entity addresses consumer billing disputes?
- Which entity is obligated to negotiate and track payment agreements?
- What are the eligibility standards for customers to participate in SCB?
- What occurs if an SCB customer fails to pay in full?
- What occurs if the EDC fails to submit billing information?
- What is the obligation of the EGS to handle hardship fund donations?
- Can utilities that provide and bill for both electric and gas segregate electric from gas charges if only the electric charges are SCB?

Given the complexities and controversies mentioned above, OCMO, after consulting with the Commission, decided that SCB could not be effectively addressed using an informal process such as CHARGE. It was decided, instead, to refer SCB to the

Investigation. While it is apparent that the issues remain numerous and complex, none of these concerns present an insurmountable obstacle to making SCB available. In the *Tentative Order*, the Commission proposed that, by July 1, 2013, OCMO was to provide a recommendation to the Commission as to how to proceed with making SCB available as a billing option. At the same time, we emphasized that we were proposing SCB as a billing option only – joining, not replacing, the other billing options that are currently available (utility consolidated billing and dual billing).

1. Comments

Consumer representatives express numerous concerns, especially relating to the application and enforcement of consumer protection laws in an SCB environment. OCA believes that it is premature to require SCB, at this time, due to limited interest from EGSs and that there has been no determination of the costs of this effort and whether the benefits would justify such costs. OCA submits that the costs of SCB should be borne by EGSs. Further, if SCB is pursued, OCA insists that all consumer protections be maintained. OCA at 18.

PULP questions if it is even possible to get the multitude of licensed suppliers to comply with the provisions of Chapter 56 when it is hard to get seven EDCs, who are closely regulated by the Commission, to recognize these provisions. PULP at 19. PULP also questions the Commission spending limited resources to develop a billing option that, in PULP's opinion, is not authorized by Section 2807(c) of the Competition Act, 66 Pa. C.S. § 2807(c). PULP does not believe that the Commission's stated intent that SCB only be an option available to the customer reflects the realities of the retail market. A customer who is shopping, PULP adds, is not typically able to negotiate individual contract terms, such as billing options, in that most EGS contracts are take it or leave it offers. PULP at 18.

PCADV shares PULP's concerns with the effectiveness of applying consumer protection rules to numerous EGSs, especially the protections intended for victims of domestic violence. PCADV points out that it has taken many years to educate the EDCs to ensure that victims are able to access the relief to which they are entitled and that PCADV and its member programs would be forced to spend significant resources and time to develop similar working relationships with the many EGSs. PCADV at 5.

DLC and PPL join PULP in questioning the legal foundation for SCB, pointing out that Section 2807(c) of the Competition Act does not mention it. DLC at 5; PPL at 24. PPL adds that SCB is likely to be costly and that the lack of an SCB option has not been discussed or identified as being an impediment to shopping. As such, PPL suggests that the Commission move cautiously and seek simple, cost-effective solutions. PPL at 24 and 25. DLC, Pike and Citizens' and Wellsboro believe that duplicative EDC and EGS billing systems will result in duplicative costs ultimately being borne by customers. DLC at 4 and 5; Pike at 7-10; Citizens' and Wellsboro at 7 and 8. FE comments that the complexity involved in the implementation of SCB is vast and questions the level of interest in it. FE notes that EGSs did not use it in the past and that, given the implementation of EDC purchase of receivable (POR) programs, which are tied to EDC consolidated billing, it would seem that from an economic perspective, EGSs would have even less interest in SCB than they did over a decade ago. FE at 8.

PECO believes that SCB can be an important billing option for both EGSs and customers and, while it presents many technical and legal questions, these can all be addressed through continuing stakeholder discussions. This would include recovery for both implementation and ongoing costs. PECO at 16. Many suppliers, likewise, support SCB and urge the Commission to proceed in that direction. WGES believes that SCB will break the customer's inherent bias towards remaining with the EDC. WGES at 2. NEM points out that suppliers currently operating in Texas and Georgia have expertise with SCB and that its adoption here may facilitate market entry by these suppliers to operate and do business in Pennsylvania. NEM at 7. PEMC applauds the PUC for advancing this option, but believes that utility-consolidated billing should be retained for the use of EGSs, especially smaller EGSs, that may not want, or be able, to perform SCB. PEMC at 8.

NRG notes that existing EDC billing systems are designed for tariffed utility services and that they cannot accommodate the plethora of billing needs of multiple EGSs, which prevents EGSs from offering products and services aimed at helping customers. NRG believes that utility-consolidated billing precludes EGSs from billing for new and innovative services. NRG at 9. RESA supports SCB because, under the current system, the EDC reinforces its relationship with the customer every month with its EDC-branded billing. RESA adds that an effective SCB program will have to include additional tools for EGSs in managing bad debt risk, including the ability to terminate service to customers for nonpayment. RESA at 14 and 15. In addition to SCB, RESA requests that the Commission consider requiring EDCs to unbundle their billing functions. Utilities would then tariff their billing functions and require suppliers to buy billing services at cost-based rates. RESA notes that, under this approach, customer care and billing costs would be removed from distribution rates and all customers, both default and shopping, would pay the same rate for access to the regulated utility bill. RESA adds that a similar outcome could be achieved by designating a third party entity to handle the billing for those EGSs that choose to use it. RESA at 15.

2. Resolution

While the Commission is of the opinion that SCB might someday play a role as a billing option in the competitive market, upon review of the comments, we have to conclude that we are not prepared to move to an SCB environment at this time. We agree with many of the suppliers who point out that SCB will facilitate the offering of innovative new products and services and will also help the supplier in establishing a brand identity with the customer. However, all parties appear to be in agreement that SCB could only be implemented after extensive work and expense by many entities. We are concerned with the burden this would impose, especially given the multitude of other, more critical, changes we are mandating in the near-term. We are also concerned that the extensive work and expense could result in a feature that will not be utilized sufficiently to justify the costs at this time.

We have substantial concerns that use of an SCB process may be even more unlikely now since POR programs are available. It is unclear how many suppliers would be willing to forgo the ease and convenience of utility consolidated billing under POR, where they have no bad debt risk, to opt for an SCB model where they assume the full burden of billing, collections and bad debt. We also point out that suppliers do currently have the option of issuing a separate bill to the customer (the dual billing option) if they find utility consolidated billing not conducive to their offerings or business model.

Therefore, the Commission will revise what we proposed in the *Tentative Order* – OCMO will not be submitting a recommendation to the Commission in July 2013 as to how to proceed with SCB. Instead, we direct OCMO to explore another possibility, more along the lines of what PPL suggested, to seek "simple, cost-effective solutions." By the end of 2013, OCMO should submit a recommendation regarding the possibilities for making the utility consolidated bill more supplier-oriented. The current utility consolidated bill looks like the utility's bill – with supplier information often relegated to a few lines, with the supplier's name, phone number, rate and charges. This is an especially incongruent result for many customers whose supplier generation charges actually exceed the utility's distribution charges. We are interested in pursuing options to make the supplier's charges and information more prominent. This could include making the supplier information more visible, incorporating the supplier's logo, providing more space for suppliers to provide bill messages and even the opportunity to include EGS bill inserts. The expected end-result would look more like a joint EDC-EGS bill.

We acknowledge that considerable work and some expense may be required to move to this kind of format. But we expect that the effort and expense necessary for this kind of effort will be considerably less than what would be required to create SCB. We also acknowledge that this issue has not been fully vetted through any informal or formal Commission process. Therefore, we will proceed cautiously and ask OCMO to consult with utilities, suppliers and consumer representatives as they explore the feasibility of this proposal.

We believe that this approach offers several advantages over creating an SCB environment at this time. As we have noted, we fully expect that this approach will require fewer resources than would be required to implement an SCB environment. In addition, this approach does not raise the consumer protection concerns expressed by OCA, PULP, PCADV and others, since we are not changing the entity that is billing and collecting from the consumers.

While we do find merit in RESA's comments about unbundling the EDC billing function, we decline to pursue such an effort at this time. This concept has not been fully vetted in this proceeding. Additionally, we have some of the same concerns with this that we have with SCB – this would be a significant undertaking requiring the time and resources of many stakeholders. However, this decision does not preclude the Commission from addressing the unbundling of EDC billing functions in another proceeding in the future.

We reiterate that we are not dismissing SCB. We simply find that, at this time, there are other, more pressing priorities. We are still of the opinion that SCB can play a role in the competitive energy environment and the Commission will reconsider SCB at some point in the future. When and how we proceed with SCB will depend, in part, on the results of the changes we are proposing to the utility consolidated bill, as discussed previously. We look forward to exploring the possibilities of a more supplier-oriented utility consolidated bill and invite all interested stakeholders to participate in this effort.

I. Accelerated Switching

Presently, a change in supplier can take from 16 to 45 days. This timeframe is a result of a variety of Commission regulations and EGS and EDC procedures that were established, in large part, to guard against "slamming," the unauthorized change of a supplier. In 1998, the Commission promulgated regulations to address the supplier switching process and to guard against slamming. These regulations are found at 52 Pa. Code § 57.171 – § 57.179 (relating to standards for changing a customer's electricity generation supplier). Included in these regulations is a ten-day waiting period, 52 Pa Code §§ 173- 174, which provides the customer time for contacting the utility to cancel the switch in cases where the customer did not authorize the switch of supplier. This ten-day waiting period is a significant part of the 16- to 45-day switching timeframe mentioned above.

As the market has evolved since 1998, the delay in transferring a customer's account has been noted by some consumers as a lost savings opportunity that, in turn, results in customer frustration and disappointment and a less-than-favorable opinion of the competitive retail market. Because of these concerns, OCMO explored options to shorten the timeframe for switching to an EGS.

These efforts resulted in interim guidelines that put in place temporary waivers of 52 Pa. Code §§ 57.173 – 174 to the extent necessary to shorten the current 10-day confirmation period to 5 days. *See, Final Order, Interim Guidelines Regarding Standards for Changing a Customer's Electricity Generation Supplier*, Docket No. M-2011-2270442 (Order entered October 24, 2012). This Final Order also directed Commission staff to initiate a rulemaking to review and revise the switching regulations at 52 Pa. Code §§ 57.171 – 179. The rulemaking will explore methods to accelerate the switching timeframes beyond simply shortening the confirmation period. This could include off-cycle switching and other processes made possible with the deployment of advanced metering. Possible interim switching procedures, to be utilized until the full deployment of advanced metering, may also be considered.

In addition to the above Guidelines and the directed rulemaking, we invited comments on other related issues that involve the switching process, including "seamless moves" and "instant connect." A "seamless move" is the ability of a customer's choice of supplier to move with the customer to a new address without interruption. "Instant connect" is the ability of supply service to start on "day one" of new utility service – without the customer first having to go on default service. These two processes are currently not available. The EDCs point out that their systems are not designed to allow for these enrollment options.

1. Comments

Concerning accelerating the switching process, PEMC, NRG, NEM, WGES, FES, and PPL support the Commission's proposal to proceed with a rulemaking. PEMC at 8; NRG at 11; NEM at 8; WGES at 3; FES at 5; PPL at 26. However, RESA believes that a stakeholder process should be convened to develop the shortest possible switching timeframes. RESA at 17. FES suggests that the Commission eliminate the five-day waiting period. FES at 5. OCA agrees that lengthy switching delays can result in customer frustration and supports the Commission's efforts to improve the efficiency of customer switching. However, OCA also asks the Commission to properly protect customers from unauthorized switching while pursuing the acceleration of switching. OCA at 19.

PPL and DLC believe that off-cycle switching is linked to advanced- metering. PPL at 26; DLC at 9. WGES agrees but suggests that the rulemaking address advanced metering so that the new regulations will be in place by the time the meters are deployed. WGES at 3. FES differs in that they want the Commission to allow mid-cycle switches based on estimated meter reads while awaiting deployment of advanced metering. FES at 6. PECO mentions that recovery of costs needs to be addressed and Pike asks that any existing waivers of the rules currently in place for specific EDCs remain in effect. PECO at 17; Pike at 10 and 11.

With regard to seamless moves, RESA suggests that the Commission establish firm goals and timelines for the EDCs to submit plans to the Commission detailing how they will enable these (and instant connects) in their service territories. RESA at 18. NEM suggests that rules should explicitly recognize that contracts and supply service should move with the customer to a new location, as long as the supplier can serve the new location and the new location accommodates the same type of energy supply. NEM at 8. NRG believes that a seamless move process without interruption in EGS service is fundamental to improving the customer experience in a competitive market. NRG at 11.

In general, suppliers strongly support the "instant connects" that would allow a new utility customer to start receiving supplier service on day one. RESA believes that ensuring that customers have the ability from day one to begin service with a new supplier is an important part of leveling the playing field between the DSP and competitive suppliers. RESA at 17. Likewise, EGSP believes that the inherent advantages of DSPs, like receiving all customers first, needs to be mitigated or eliminated. EGSP would go still further and require all customers to choose an electric provider when establishing service. EGSP at 6 and 8.

NRG thinks that the ability to enroll with a supplier at the time of new service is essential to eliminating the inherent presumption that EDC's "own" their customer from the outset. NRG at 11. NEM states that the current presumption that consumers start service as utility commodity customers is inconsistent with the retail market goals enunciated by the General Assembly and the Commission, and further, this presumption reinforces consumer apathy. NEM at 8 and 9. PEMC views "instant connects" as the next logical step for the marketplace and FES states that EDCs need to implement the technology to allow instant connections on day one of utility service. PEMC at 8; FES at 7.

No party opposes the concept of seamless moves or instant connects. Pike does note that this kind of capability would require considerable expense and that the costs should be borne by the EGSs. Pike at 11 and 12. NRG notes that PECO proposed, in their most recent DSP filing, to initiate a collaborative to develop technical requirements and cost estimates for the system changes that will be needed. NRG suggests that all EDCs do the same. NRG at 11 and 12. OCA supports seamless moves and does not object to exploring instant connects, but believes that the costs and benefits have to be considered. OCA at 19. Citizens' and Wellsboro likewise believe that costs need to be considered. Citizens' and Wellsboro at 8. Several EDCs noted that extensive system changes will be required to facilitate this kind of functionality and that cost recovery needs to be addressed. PPL at 26; PECO at 17; Citizens' and Wellsboro at 8; FE at 9 and 10. FE also asks that, due to the extensive programming tasks that are involved, implementation be required no earlier than June 1, 2015. FE at 9.

2. Resolution

Based on the general agreement of the parties, we will proceed with our previously announced intention of initiating a rulemaking by the end of 2013 to revise the switching regulations, with the intent of accelerating the switching process. A rulemaking will provide all interested parties with the opportunity to participate and will allow the Commission to make fully informed decisions on the complex issues involved. The use of a formal rulemaking should also help clarify any cost-recovery issues. Because the resulting costs will flow as a result of a final Commission order and regulatory requirements, cost recovery for these changes should be handled the same as any costs a utility incurs as a result of a Commission mandate.

By choosing to initiate a rulemaking, we are rejecting the use of a collaborative process. We believe most of these issues have already been aired via one working group or another (including the RMI) and that there is little, if anything, to be gained by further informal discussions. Also, given that this involves a change to existing regulations, a rulemaking is the legally appropriate venue for addressing these issues.

We understand the concerns expressed by some of the parties that off-cycle switching should be contingent on advanced metering. However, we do not, at this time, want to restrict the consideration of any possible approaches raised in the rulemaking and believe it is best to leave the resolution of this issue to that forum. We do agree with WGES that the role of advanced metering should be considered in the proposed rulemaking so that updated regulations can be in place by the time advanced meters are deployed. Also, once the new regulations are promulgated, Pike, given their unique circumstances, can make a determination as to the need for a waiver at that time and file a petition with the Commission if they believe such is still needed.

While the Commission intends to initiate a rulemaking to look at the switching regulations, in doing so, we do not rule out the possibility of exploring statutory changes that would complement or assist with these efforts, especially in the context of using advanced metering. To date, most of the discussion on the use of advanced metering has centered on their use in billing and load management. However, we believe that this discussion has to be expanded to also consider their role in the supplier switching process. As such, the Commission will consider whether or not statutory changes are needed to facilitate or clarify the use of advanced meters in the switching process.

We are also of the opinion that the implementation of seamless moves and instant connects does not have to wait until after a rulemaking is completed. While we acknowledge that there are several procedural and programming (including possible EDI) changes that may be required to implement seamless moves, we are unaware of any specific regulation or statute that would bar them. To the contrary, we believe seamless moves are a natural and expected part of the competitive market that have only been hindered by the current limitations of EDC account information systems. As such, we do not believe it necessary to promulgate a new section of regulations to address this limited, discrete function. Therefore, we direct the EDCs to develop and submit plans to the Commission by the end of 2013 to implement seamless moves in their service territories by June 1, 2015. The EDCs' plans should also address costs and proposals for the recovery of those costs. While we believe it is important for EDCs to develop these plans with input from suppliers, we do not think a special, statewide collaborative process for this purpose is necessary. Instead, we direct EDCs to utilize their existing supplier-consultation processes in developing the plans. If any party believes that, at any point, the consultation process is not working as needed, that party should contact OCMO and seek assistance and direction.

Likewise, the implementation of instant connects does not require the promulgation of new regulations. However, we do acknowledge that instant connects may be more complicated in that the supplier switching regulations may have to considered, and perhaps even waived to some limited extent. For example, what role, if any, does a confirmation letter have in an instant connect process? Due to these regulatory questions, we must make sure that the instant connect process is considered and accommodated in the supplier switching rulemaking discussed above. Regardless, we do not believe that an exploration of instant connects need await the promulgation or revision of these rules. For the reasons cited by the supplier community, we believe that the ability of a new customer to instantly connect to their selected EGS is a vital mechanism that will go far in making default service truly "default." As the suppliers point out, requiring all customers to first go on default service before obtaining service from a competitive supplier inappropriately makes the default service the "primary" service. This too easily hands the DSP customers who may stay with default service simply out of inertia. This is unacceptable. As such, we direct the EDCs to develop and submit plans to the Commission by the end of 2013 to implement instant connects in their service territories by June 1, 2015. The EDC's plan should also address costs and proposals for the recovery of those costs. We also direct the EDCs to utilize their existing supplier-consultation processes in developing the plans. If a party believes that the intervention of the Commission is needed at any point, that party should contact OCMO.

J. Provision of Metering Services

1. General Metering Services

The Commission, in its *Tentative Order*, proposed that the EDCs retain general metering services, such as the provision of meters and performing all relevant PJM settlement tasks. The Commission stated that this would allow for the continued use of invested infrastructure and the experience of the EDCs, as well as prevent potential smart meter implementation issues. *Tentative Order* at 31-32.

a. Comments

Citizen Power, FE, OCA, PECO, RESA and WGES all agree with the Commission's proposal to have EDCs retain general metering services. Citizen Power at 5; FE at 10; OCA at 4 and 20; PECO at 17; RESA at 18 and 19; WGES at 3. FE states that, in the past, competitive metering has been explored; however, no interest was expressed in offering such services. FE at 10. PECO avers that moving metering services away from the EDCs could cause issues with the implementation of smart meters. PECO at 17.

NEM and PEMC agree that the EDCs should retain general metering services with the caveat that EGSs get open, non-discriminatory, real-time access to meter data. NEM at 9; PEMC at 9. PEMC states that advanced metering infrastructure (AMI) data must be provided to EGSs to allow for the development and implementation of a variety of customer offerings. PEMC at 9.

b. Resolution

The Commission maintains its position that the EDCs should retain general metering services with the implementation of this default service model. This includes the provision of meters, activities associated with the reading of meter data, associating that meter data with the appropriate billing data and performing all relevant PJM settlement tasks.[26] EDCs already have the capability and infrastructure necessary to offer these services. Additionally, we agree with PECO that moving these services away from the EDCs, at this time, may affect the implementation of smart meter technology.

However, the Commission recognizes the concerns expressed by the EGS community regarding access to meter data. We continue to encourage the EDCs to work collaboratively with the EGSs and third parties to allow for open access to customer AMI and/or smart meter data. The EDCs are still required to meet the directives for EGS and third party access to data as outlined in previous Commission Orders.[27] We agree with

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[26] The EDC-provision of metering services will not affect any metering provided to customers by PJM Curtailment Service Providers.
[27] *See, Smart Meter Procurement and Installation* Implementation Order, at Docket No. M-2009-2092655 (Order entered June 24, 2009); *Smart Meter Procurement and Installation* Final Order, at Docket No. M-2009-2092655 (Order entered December 6, 2012).

PEMC that open access to data will allow EGSs to offer more dynamic and innovative products to customers and provide for increased retail electric competition.

2. Net Metering Services

The Commission did not address the provision of net metering services within its *Tentative Order* as the proposed model maintained the EDC in the role of DSP. However, we will address comments related to such services within this section.

a. Comments

While Sierra Club believes that all EGSs should be required to offer net metering, it recognizes that this may not be possible. Sierra Club at 4. Both Sierra Club and MSEIA & PASEIA express concerns regarding the provision of net metering benefits should an EGS or alternative party be designated as a DSP. Specifically, both parties request that, should an EGS or third party be approved to act as a DSP, a condition of such approval should be the requirement to offer net metering benefits, including virtual meter aggregation, as outlined at 73 P.S. § 1648.2, at 52 Pa. Code §§ 75.13 – 75.1 and in Commission Orders. Sierra Club at 4 and 5; MSEIA & PASEIA at 3 and 4.

PennFuture and Sierra Club request that all EGSs be required to disclose net metering information, including a potential loss of benefits, to customers before enrollment occurs. PennFuture at 10 and 11; Sierra Club at 5. Additionally, PennFuture requests that the Commission include on its PAPowerSwitch.com website a list of EGSs offering net metering benefits. PennFuture at 11.

b. Resolution

The Commission recognizes the concerns of Sierra Club and MSEIA & PASEIA regarding the provision of net metering services should an alternative DSP be approved. We agree that the provision of such services must be addressed prior to the Commission's approval of such a provider. As discussed previous within this Final Order, OCMO will convene a working group to discuss the implementation of a model in which an alternative entity, or multiple entities, provides default service. The working group shall discuss the possibility of an alternative DSP providing net metering benefits and OCMO will provide a recommendation to the Commission no later than November 15, 2013.

The Commission always encourages increased consumer education when EGSs market and enroll customers to ensure that informed decisions are being made. Additionally, we are already taking steps, such as the inclusion of a net metering designation for customers on the Eligible Customer List, to inform EGSs of those customers who are receiving net metering benefits. However, we encourage all parties in the competitive market to provide as much education as possible to customers during the switching process regarding potential changes to net metering benefits.

Regarding PennFuture's request to include a net metering designation on the PAPowerSwitch.com website, CHARGE is already discussing potential changes to PAPowerSwitch.com, including such a designation. OCMO is currently working with the Commission's Office of Communications to determine the feasibility of the changes received through the CHARGE forum. We encourage PennFuture to continue participating in the CHARGE discussions regarding such changes.

K. Provision of Energy Efficiency and Conservation Programs

In its *Tentative Order*, the Commission proposed that the provision of EE&C programs be retained with the EDCs. The Commission believed this would allow EE&C measures to reach the broadest array of customers, regardless of whether or not those customers are participating in the competitive retail electric market. We also encouraged the EGSs to provide energy efficiency offerings to their customers to increase the diversity of products and services within the competitive market. *Tentative Order* at 33.

Additionally, at the Commission's November 8, 2012 Public Meeting, Commissioner Witmer issued a Statement which presented specific questions regarding existing EGS EE&C offerings and the EGSs' role in current EDC EE&C programs; the development of additional EE&C offerings by the EGSs; and how the EGSs could play a broader role in the current EDC-offered EE&C programs. *Investigation of Pennsylvania's Retail Electricity Market: End State of Default Service*; *Statement of Commissioner Pamela A. Witmer*; Docket No. I-2011-2237952 (dated November 8, 2012).

1. Comments

Citizen Power, FES, OCA, PennFuture, Sierra Club and WGES agree with the Commission that the provision of EE&C programs should remain with the EDCs. This allows the offering of such programs to all customers, providing for economies of scale and the continued use of the same conservation service providers (CSPs) across all territories for certain measures. Citizen Power at 5; FES at 7; OCA at 4, 20 and 21; PennFuture at 2; Sierra Club at 2; WGES at 3. FES states that, even if an alternative DSP is approved, the provision of EE&C programs should remain with the EDCs to continue reaching both shopping and non-shopping customers. However, in response to Commissioner Witmer's question regarding how EDCs and EGSs could coordinate services within the existing EE&C requirements, FES states that, while EE&C should be offered by the EDCs, TOU programs should solely be provided by EGSs. FES at 7.

NEM, NRG, PPL and RESA believe that the EGSs are well-equipped at competitively offering such programs and services and, as such, should be the sole parties offering such programs. NEM at 9 and 10; NRG at 12; PPL at 28-30; RESA at 19-21. In response to Commissioner Witmer's question regarding changes to the end state proposal that may encourage EGSs to develop and offer EE&C services outside the scope of Act 129, NRG proposes that the EGSs and other parties be able to compete for a share of the EDCs' EE&C funds to provide such services. NRG at 12. In response to Commissioner Witmer's question regarding a potentially broader role to be played by EGSs in the mandated EE&C programs, NRG advocates for a transition to a fully competitive market. NRG at 12. PPL and RESA support a Commission-pursuit of legislative changes to the Competition Act to remove the EDCs' EE&C requirements. PPL at 30; RESA at 20.

Citizen Power, FES, OCA and PennFuture agree with the Commission's encouragement that, while the provision of EE&C programs should remain with the EDCs, EGSs should also provide such services. This allows for more diversity in the array of products and offerings to retail electric customers. Citizen Power at 5; FES at 7; OCA at 21; PennFuture at 2. In response to Commissioner Witmer's question regarding a potentially broader role to be played by EGSs in the mandated EE&C programs, OCA states that EGSs can play a complementary role, while distinguishing themselves and their products from the EDC programs. OCA at 21.

EAP, FE and PPL opine that the Commission's encouragement to EGSs to offer EE&C programs and services, in addition to the EDCs' programs, reduces the EDCs' ability to meet consumption reduction targets, as the EGS offerings reduce the potential for energy efficiency in the state. EAP at 5 and 6; FE at 10 and 11; PPL at 28-30. As such, EAP and FE request that, should the Commission continue to encourage EGS offerings of EE&C programs, the Commission should also pursue legislative changes that remove the financial penalties (as outlined in 66 Pa. C.S. § 2806.1 (f)(2)(i)) for noncompliance. EAP at 5 and 6; FE at 10 and 11.

FE, NRG and PECO request that, should the Commission maintain its encouragement to EGSs to offer EE&C measures, the EDCs be allowed to claim those savings towards their consumption reduction mandates. FE at 11; NRG at 13; PECO at 19. FE proposes that EDC-provided EE&C rebates be bundled into EGS offerings and that EGS-provided EE&C utilize, to the extent possible, the EDC-provided products and services. FE at 11. Additionally, in response to Commissioner Witmer's question regarding how EDCs and EGSs could coordinate services within the existing EE&C requirements, PECO states that EGSs can already participate in its programs by completing rebate applications on behalf of customers and that the EDC should be able to count those savings towards its obligation. PECO at 19.

If the EDCs are to retain the provision of EE&C programs, PECO and PPL request that the Commission pursue legislative changes to remove the restriction, as outlined in the definition of a "conservation service provider" provided in 66 Pa. C.S. § 2806.1 (m), on EDC affiliates acting as CSPs. They aver that allowing affiliates to act as CSPs allows for the offering of new and innovative programs, providing a broader role for the EGSs to play within the mandated programs. PECO at 19; PPL at 30.

Commissioner Witmer solicited feedback on any EGSs currently providing, or planning to provide, EE&C services in the competitive retail market. PECO states that Exelon offers energy assessments; project financing, design and implementation; and conservation programs, like peak load management. PECO at 18. NRG asserts that Reliant Energy Northeast, LLC, currently offers TOU programs to PECO customers. NRG also states that it intends to offer more EE&C programs in Pennsylvania. NRG at

12 and 13. FES avers that, in addition to those EGSs offering TOU programs, some EGSs act as CSPs, participating in the EDC EE&C programs. FES at 8.

2. Resolution

The Commission maintains its position that the provision of EE&C programs be retained by the EDCs. As stated in its *Tentative Order*, the Commission believes that the EDC-provision of EE&C programs allows for widespread outreach to the majority of Pennsylvania's retail electric customers. The EDCs' EE&C programs also allow customers to benefit from the same, or similar, rebates and incentives. *Tentative Order* at 33. While we do not believe that EGSs could *not* offer similar programs, we believe moving the entirety of the EE&C responsibility to the competitive market, at this time, may lead to a significant loss of rebates and incentives considering the current lack of EGS-provided EE&C offerings (not including TOU rates). We believe the statewide electricity consumption reductions provided for by the EDC EE&C programs and the ability for a customer to participate in such programs regardless of whether or not they shop are beneficial to Pennsylvania ratepayers.

We maintain our encouragement to the EGSs to provide their own energy efficiency offerings in order to increase the diversity of products and services within the competitive market and to aid in the reduction of energy consumption across the state. We disagree that such encouragement will provide a largely negative effect on the EDCs' ability to meet their consumption reduction mandates. The Act 129 Statewide Evaluator's (SWE) Electric Energy Efficiency Potential for Pennsylvania Final Report[28] (Market Potential Study), from which the Commission developed the EDCs' consumption reduction mandates, outlined the opportunities, statewide, for electricity

[28] The SWE's Market Potential Study is available at the following link: http://www.puc.state.pa.us/filing_resources/issues_laws_regulations/act_129_information.aspx.

savings. The Commission is confident that, based on the results of the SWE's Market Potential Study, the EDCs should be able to meet the mandates as prescribed, with potential savings still remaining for the competitive market to procure. Additionally, non-EDC-affiliate EGSs are welcome to become licensed CSPs within the Act 129 EE&C programs to aid the EDCs in garnering savings towards their consumption reduction targets. The Commission encourages such EGS participation within the mandated EDC EE&C programs.

The Commission will not pursue legislative changes to the definition of a CSP, as defined at 66 Pa. C.S. § 2806.1 (m), at this time. We believe it was the intent of the Legislature to prevent an EDC from providing its own ratepayers' money to its affiliate, as well as to prevent one EDC's ratepayer dollars from going to the EGS affiliate of another EDC. Additionally, we have not been provided with evidence that the current restriction has impeded an EDC from meeting its consumption reduction mandates.

L. Existing Long-Term Contracts: Alternative Energy Credit, Default Service, and PURPA

The Alternative Energy Portfolio Standards Act of 2004, P.L. 1672, No. 213, (AEPS Act) became law on November 30, 2004. The AEPS Act, which took effect on February 28, 2005, established an alternative energy portfolio standard for Pennsylvania. The AEPS Act requires that an annually increasing percentage of electricity sold to retail electric customers by EDCs and EGSs be derived from alternative energy resources. The AEPS Act was codified at 73 P.S. §§ 1648.1, *et seq.*

Act 35 of 2007, P.L. 114, (Act 35) was signed into law on July 17, 2007, which took effect immediately. Act 35 amended the AEPS Act in several respects. In particular, Act 35 revised the schedule for solar photovoltaic requirements so that the requirements increase on an annual basis as opposed to increases in five year increments.

73 P.S. § 1648.3(b)(2). This legislation also made it clear that the solar photovoltaic requirement is a percentage of total retail sales, not a percentage of the Tier I requirements. *Id.* In addition, the Act 35 amendments required the Commission to consider EDCs' and EGSs' efforts in obtaining alternative energy credits through competitive solicitations and seeking to procure AECs or alternative energy through long-term contracts in any *force majeure* determination. 73 P.S. § 1648.2.

While the Commission has provided some policy guidance on AEPS contracts, specifically those relating to solar AECs, we have not directed EDCs to enter into specific types of contracts for their procurement of AECs.[29] As stated in the *Tentative Order*, the Commission proposed to hold all presently-effective AEC contracts, energy contracts that exist pursuant to previous or existing default service plans, and any contracts that exist pursuant to the Public Utility Regulatory Policies Act (PURPA) harmless from any of the changes that are effectuated in Pennsylvania's retail markets initiated by this proceeding. Therefore, on a case-by-case basis, EDCs may propose the means by which these contracts will be addressed on the issue of cost recovery. Such means may include, but are not limited to, the inclusion of incurred costs in the PTC, the inclusion of incurred costs in a non-bypassable surcharge, or the voluntary assignment to an EGS or EGSs. We proposed that each EDC provide a proposal for the management of these energy contracts in their next round of default service filings. *Tentative Order* at 34-35.

1. Comments

MAREC, PennFuture, MSEIA & PASEIA, Citizen Power, OCA, RESA, and Citizens' and Wellsboro support the Commission's proposal to uphold all presently-

[29] *See, Policy Statement in Support of Pennsylvania Solar Projects* Final Policy Statement Order, Docket No. M-2009-2140263, (Order entered September 16, 2010).

effective AEC and energy contracts. MAREC at 2; PennFuture at 3; MSEIA & PASEIA at 2; Citizen Power at 5 and 6; OCA at 21 and 22; RESA at 21 and 22; Citizens' and Wellsboro at 9. PennFuture, OCA and Citizens' and Wellsboro also support the Commission's recommendation to allow each EDC to provide a proposal for the management of existing long-term contracts in their next round of default service filings. PennFuture at 3; OCA at 21 and 22; Citizens' and Wellsboro at 9.

ConEd also supports the proposal, but also seeks specific language directing that any cost recovery for such contracts be implemented in a competitively neutral fashion. ConEd at 5 and 6.

The Industrials agree with the Commission, that the appropriate venue to address cost recovery with respect to all existing long-term contracts is the default service plan proceedings. The Industrials however, go on to opine that some of these contracts may be serving only particular customer classes and traditional cost causation principles would support allocating the costs only to that class. The Industrials propose that the Commission should clarify that a "non-bypassable surcharge" can be class-specific rather than a uniform charge across all customer classes to resolve any uncertainty. Industrials at 10.

2. Resolution

The Commission will maintain its proposal as described in the *Tentative Order* to hold harmless all existing AEC, default service, and PURPA contracts from changes made during this proceeding. Additionally we direct the EDCs to allocate costs of contracts to rate classes for which the contracts were intended and to strive to recover contract costs in a competitively neutral manner.

M. Future Long-Term Alternative Energy Credits Contracts

In the *Tentative Order,* the Commission requested comments on whether an EDC or an alternative DSP approved by the Commission, consistent with 66 Pa. C.S. § 2807(e)(3.1) and applicable regulations, should file a procurement plan for Tier I, Tier II, and Solar AECs with the Commission. We also requested that parties address whether it would be more appropriate to have this function fulfilled by an EDC (regardless of whether it has a default service obligation) or the entity providing default service. Comments were requested on whether these procurements should include a mix of short-term (one year or less), medium-term (one to five years), and long-term (six to ten years) contracts, or whether procurements should be EDC territory fact-specific, tailored specifically to each EDC territory's unique circumstances, requirements and market conditions. If procurements were to be a mix of contract durations, we requested comments on whether the procurement schedules should aim to procure AECs necessary to comply with up to 50 percent of the zonal load for any given service territory and allocate those AECs on a pro-rata share basis among the EGSs operating in its zone, entirely among the default service load, or some mixture of both. *Tentative Order* at 36-37.

1. Comments

Sierra Club differentiates the risks associated with conventional generation resources from the risks associated with alternative energy resources. Specifically, Sierra Club submits that future variable costs are the largest risks for conventional wholesale generation resources. Conversely, Sierra Club avers that the variable costs for alternative energy resources are minimal and predictable. Sierra Club states that that the risks in developing resources such as wind and solar are largely derived from the potential for future demand to be sufficient to cover the capital cost of development. Consequently, Sierra Club submits that long term contracts for alternative energy resources will actually lower costs of development by removing this uncertainty. Sierra Club also states that long term contracts will provide alternative energy developers financing at lower interest rates which will ultimately lead to lower AEPS compliance costs. Sierra Club at 3.

Sierra Club argues further that the absence of long-term AEC contracts will make it more difficult to finance new alternative energy resource development. Future increases in AEPS requirements will, in turn, increase AEC demand and appreciate the value of AECS. However, Sierra Club opines that higher-priced AECs in the short term are unlikely to stimulate sufficient new development of alternative energy generation, as the risk of not meeting the revenue requirements still remains. Sierra Club concludes that the absence of long-term AEC contracts will either force ratepayers to pay sustained high prices for short term AECs or result in a failure of the market to meet the demands of the AEPS mandates at some point in the future. Consequently, Sierra Club advocates that the Commission adopt a policy that allows for the use of long-term contracts for Tier I AECs sufficient to stimulate and maintain a market for new development of these resources. Sierra Club at 3.

Sierra Club also requests that each EDC submit to the Commission an AEC procurement plan regardless of whether or not the EDC is the DSP. Sierra Club believes such plans will enable the Commission to determine whether each EDC has dedicated the appropriate level of resources to AEPS compliance. Sierra Club states that, since the EDCs have the most predictable customer base from year to year, that they are in a better position to enter into long term contracts. Sierra Club at 3.

Last, Sierra Club supports the concept of having EDCs procure AECs to cover 50 percent of the zonal compliance requirements for each year. Sierra Club believes that at least half of the AEC contracts to support this 50 percent portion should be of a time period that is ten years or greater and that the remaining portion should be five years or more. The other 50 percent of the AECs can be procured using any contract length deemed appropriate by the EDC or EGSs. Sierra Club states that, if an EDC's AEC compliance requirement is reduced to less than 50 percent of the zonal load, then the procured AECs can be allocated to EGSs on a pro-rata share basis while recovering costs through a non-bypassable surcharge. This method, Sierra Club avers, eliminates any risk for the EDC to enter into long-term AEC contracts. Sierra Club at 3.

Concerning future AEC procurements, MAREC submits that the Commission is granted broad authority under Act 213, as amended, to administer the alternative energy system of payments. MAREC opines that there is no language in Act 213 that directs the Commission to implement a model where the EDCs or EGSs procure AECs jointly and/or exclusively. MAREC contends that the Act is strictly concerned with the mandatory delivery of alternative energy to the market. MAREC at 5. MAREC states that the Commission's lack of any previously-mandated AEC longevity is not a barrier to implementing such a mandate now. Consequently, MAREC endorses the following long-term AEC procurement proposal:

- EDCs are mandated to procure 50 percent of the AECs per year required for AEPS requirements in their zones;
- Half of the procurements be for ten-year fixed price contracts and the other half for 5-year fixed-price contracts;
- EDCs retire AECS on behalf of EGSs and themselves based on a pro-rata share of EGS and EDC retail customers in a given EDC territory;
- EDCs recover costs through a non-bypassable surcharge;
- EGSs AEPS compliance obligations be reduced based on the AECs retired by the EDC on their behalf; and,
- EDCs conduct competitive, long-term AEC procurements annually until such time that the Commission determines that sufficient resources exist to meet AEPS requirements in the long-run.

MAREC at 8.

MAREC submits that it is essential that AECs send price signals sufficient to encourage development of new AEPS resources to meet the law's requirements. MAREC details that, for this reason, renewable energy developers argue that long-term contracts provide the most efficient and best price signal. Continuing, MAREC states that the pricing of AECs is primarily associated with the recovery of long-term capital costs, which is contrary to the conventional generation market in which pricing is largely associated with variable costs. MAREC contends that relying on short-term markets for AECs will result in prices that are either too low or too high. In turn, this will create unnecessary price volatility for ratepayers and potentially discourage investment in required AEPS-qualifying capacity. MAREC at 12.

PennFuture submits that the proposed end state of default service, which relies on shorter-term default service energy procurements to facilitate retail competition, is detrimental to the development of renewable energy resources. In support, PennFuture avers that increased shopping will make EDCs reluctant to procure large portions of AECs and that EGSs are already unlikely to procure long-term AEC contracts due to high fluctuations in load. However, Penn Future contends that this issue is not isolated to Pennsylvania. Other states such as New York, New Jersey, and Rhode Island have endorsed the procurement of long-term AECs either via a central procurement model or requiring EDCs to procure a prescribed amount of AECs. PennFuture at 3 and 4.

PennFuture and MSEIA & PASEIA contend that an appropriate model for Pennsylvania would be to place a percentage of the AEPS compliance on the EDCs to be procured through a mix of long and mid-term AEC contracts. PennFuture and MSEIA & PASEIA recommend that EDCs procure 50 percent of their Tier I and solar zonal AEPS requirements, regardless of the EDC's default service obligation, through a mix of ten-year and five-year Tier I and solar contracts. PennFuture and MSEIA & PASEIA propose that the EDCs recover the costs for these contracts through a non-bypassable rider. PennFuture at 4; MSEIA & PASEIA at 2 and 3. In support of its proposal, PennFuture submits that there is already precedent for this approach. Namely, Met-Ed, Penelec, and Penn Power currently have mechanisms in place to allow for the purchase of long-term solar AECs. PennFuture believes that its proposed model creates a mix of reasonable contract lengths. The 50 percent of AEPS compliance that remains with EGSs could be met through short-term and spot market procurements, while EDCs would enter into long-term contracts to help facilitate the build-out of renewable energy resources. PennFuture at 7-9.

PA Chamber opposes the Commission's proposal to have EDCs enter into long-term AEC contracts. PA Chamber submits that the requirement of such contracts undermines the competitiveness of the electricity marketplace in Pennsylvania by shifting financial risks for AEPS generation facilities from developers to consumers. PA Chamber avers that the consequence will be that consumers end up paying more for electricity. Also, requiring EDCs to execute long-term AEC contracts and assigning the AECs to EGSs can end up interfering with the arrangements that customers negotiate with their retail suppliers. Last, PA Chamber avers that, according the Commission's 2011 AEPS Report,[30] there are sufficient alternative energy resources in PJM to meet AEPS requirements, therefore eliminating any need to mitigate financial risks. PA Chamber at 1 and 2.

Citizen Power believes that EDCs should be required to file AEC procurement plans with the Commission. Citizen Power avers that these plans should be comprised of a portfolio of medium and long-term AEC contracts that total 50 percent of the Tier I and solar AECs required for a given EDC, with half of the contracts for AECs being medium-term and half being long-term. Citizen Power submits that the AECs should be allocated

[30] The Commission's Alternative Energy Portfolio Standards 2011 Annual Report is available at the following link: http://www.puc.state.pa.us/consumer_info/electricity/alternative_energy.aspx.

to the default service load. If default load drops below 50 percent of the zonal load, the difference should be allocated to EGSs on a pro-rata basis based on EGS load. In support, Citizen Power states that the EDC, whether or not the DSP, already has experience with AEC procurement. Additionally, Citizen Power asserts that keeping the EDC in this role will avoid the potential transfer or assignment of contracts to any newly appointed DSPs. Last, Citizen Power contends that long-term contracts are preferable because they guarantee a stream of income for potential renewable generation projections. Citizen Power argues that this creates a reduction in risk for renewable generators and, in turn, avails the market to lower financing rates. Citizen Power 6 and 7.

The Industrials state that current statutory provisions neither mandate nor prohibit EDCs from entering into medium- or long-term AEC contracts. In general, the Industrials support an EDC-by-EDC resolution to this issue based on the characteristics of each EDC service territory. The Industrials aver that making a specific procurement mix a requirement may result in unintended consequences, such as customers paying AEC costs that are not consistent with current market conditions because the contract was executed five or ten year ago. Further, the Industrials maintain that the Commission's tentative proposal could result in a scenario where the EDC or the DSP has more AECs than necessary. In such a case, the solutions suggested in the *Tentative Order* interfere with the negotiations between customers and EGSs and could result in customer paying twice for AECs. Consequently, the Industrials urge the Commission to reconsider its proposal. Industrials at 11 and 12.

OCA supports the implementation of a procurement structure that fosters the successful development of alternative energy resources. OCA believes the Commission proposal for more short-term default service energy procurements will not likely achieve this result. OCA further states that the EDCs' upcoming default service plans handle AECs in different manners and that these experiences will allow for a more fully-informed discussion of the best method for meeting AEC obligations. OCA at 22 and 23.

PPL opines that requiring EDCs or the DSP to enter into long-term AEC contracts is not necessary to help Pennsylvania meet its alternative energy goals. PPL states that such a requirement is anti-competitive and contrary to the objectives of the Investigation. PPL contends that there is no evidence to suggest that the competitive market is not working to meet the AEPS goals, but rather, that the currently-suppressed price for AECs due to excess alternative energy generation resources is demonstration that the market is sending proper price signals. Finally, PPL asserts that the development of generation through non-bypassable charges will distort the competitive market and hinder future development of generation without subsidies. PPL at 31 and 32.

FE submits that the obligation to provide AECs should continue to be placed on the load serving entity (LSE), regardless of whether the LSE is an EGS or the wholesale supplier of energy to the DSP. However, FE states that if an EDC acquires additional long-term AECs they should be provided to EGSs and DSP suppliers on a load share basis. Further, the costs should be recovered from all customers via a non-bypassable rider. FE at 11 and 12.

FE avers that, given the current over-supply of AECs, as well as the Commission's estimates for future demand of Pennsylvania AEPS qualifying AECs, there will no longer be a need for EDCs to procure contracts on a long-term basis in order to support alternative energy development after the expiration of the upcoming default service plans, which expire on May 31, 2015. FE also states that if these circumstances should change, this issue could be revisited at that point in time. FE at 12 and 13.

Citizens' and Wellsboro contend that requiring small EDCs to implement a portfolio approach for AEC procurements may present challenges. For instance, the total AEC requirements for small EDC territories may be too small to warrant segregation into short-, medium-, and long-term transactions. As such, Citizens' and Wellsboro request that the Commission adopt a flexible approach that allows each EDC to determine, within their default service plan proceedings, whether such an approach is both feasible and rational for implementation. Additionally, Citizens' and Wellsboro request that the Commission ensure that EDCs will be entitled to full cost recovery for any short-, medium-, or long-term AEC procurements. Citizens' and Wellsboro at 9.

EAP expresses concern that the Commission's proposal to establish rules for EDC AEC procurements may unnecessarily increase alternative energy mandates. First, EAP submits that the AEPS Act mandates the amount of AECS EDCs and EGSs must purchase but not the type of contract they must enter into. Second, EAP contends that the Commission's proposal is inconsistent with the Commission's Solar Policy Statement, which only encourages, but does not require, EDCs to enter into long-term solar AEC contracts. EAP states that there are sufficient AECs in the market, at present, to satisfy AEPS mandates without mandating long-term contracts. As such, EAP contends that the AEPS is working and there is no need to compel such a procurement structure. Lastly, EAP believes that such a mandate shifts risks from developers to customers, which EAP avers is contrary to the purpose of the Competition Act. Consequently, EAP believes the Commission should not compel EDCs to file procurement plans requiring a mix of contract lengths for AECs. EAP at 6 and 7.

COMPETE strongly opposes the Commission's proposal to have the DSP enter into a mix of short-term, medium-term, and long-term AEC contracts. COMPETE submits that this requirement would increase costs by forcing customers to pay for generation development before it is needed. COMPETE compares the assured cost recovery created in this proposal to the historical regulated generation environment which led Pennsylvania to restructure its market and provide customer choice in the first place. COMPETE also states that forcing customers to pay for these contracts through a non-bypassable surcharge, when alternatives exist in the market, deprives customers of the flexibility to choose the EGS and product that best suits their needs. Further, COMPETE opines that subsidies for development through non-bypassable surcharges will distort the market and significantly impact the ability of future generation to be developed without its own additional subsidies. Consequently COMPETE urges the Commission to modify its proposal to allow customers to continue to choose for themselves how best to meet their own individual electric needs. COMPETE at 3-5.

RESA does not support the Commission's proposal to require EDCs to procure up to 50 percent of the AECS required for all load in the EDC's service territory. RESA states that removing the AEC procurement responsibility from EGSs effectively denies EGSs an opportunity to enact competitive strategies to procure AEPS supply more efficiently. RESA recognizes that some EDCs already procure AECs on behalf of EGSs. RESA submits that, in these territories, it may be appropriate to maintain the status quo in order to avoid disrupting existing retail contracts and EGS procurement strategies. RESA at 23. RESA further submits that the current glut of AECs in the market gives the Commission more time to assess whether the competitive market can continue to be an efficient and cost-effective way to balance the supply and demand of AEPS eligible generation. If this glut diminishes, the Commission may, in the future, determine requirements to help achieve the goals mandated in the AEPS legislation. RESA at 24 and 25.

ConEd submits that properly-implemented, long-term AEC contracts by EDCs can be an effective policy tool to promote the continued build-out of alternative energy resources. It avers that cost recovery is a critical issue to consider when formulating an effective approach. ConEd believes there are three general approaches that can be utilized for AEC procurements. First, ConEd describes a scenario where the EDC procures AECs for all load and recovers costs through a non-bypassable surcharge. This approach is already used in the Met-Ed and Penelec service territories. ConEd believes this approach helps to stimulate demand and stabilize future revenue streams for solar projects in a competitive neutral manner. However, ConEd contends that a downside arises by eliminating the EGSs ability to form strategies to compete with each other in the AEC market. ConEd at 3.

Second, ConEd describes the option where AEC requirements are placed upon wholesale, full requirements suppliers of default service load. In this case, these costs are fully bypassable by customers because the costs are embedded in the PTC. Also, EGSs retain the liability to comply with AEPS and, therefore, will include those costs within their competitive offers. This model gives EGSs the ability to gain competitive advantages through their own management of AEPS compliance mandates. However, ConEd opines that this method may create little incentive for market participants to enter into long-term AEC contracts because EGS customer bases are migratory and default service contracts, as proposed in the *Tentative Order*, will only be for three months. Consequently, ConEd submits that this method may not meet the Commission's policy objective of promoting renewable development by encouraging long-term AEC contracts. ConEd at 3 and 4.

Third, ConEd describes an option in which an EDC would procure a specified amount of AECs through a separate procurement and use these AECs to fulfill some of its AEPS requirements. ConEd asserts that, under this approach, the PTC reflects the combination of the EDC's cost of AEPS procurements plus the residual amount of AECs that wholesale suppliers are responsible for, which is imbedded in default service bid prices. ConEd at 4 and 5.

PECO avers that the *Tentative Order* section regarding Future Long-Term AECs is based on the mistaken belief that the DSP procurement of a portion of AEPS requirements through subsidized long-term contracts will help facilitate a successful capacity build-out of AEPS-qualified generation facilities and help to ensure that the percentage goals of AEPS are met. PECO argues that the proposal errs in in three areas: (1) risk increases consumers' prices for AEPS compliance; (2) deter competitive investment in renewable resources; and, (3) impede the competitive retail market. PECO at 20.

PECO points to PURPA, where utilities were required to enter into long-term contracts with the express intent to incent the development of renewable energy technologies and cogeneration. PECO opines that the result of PURPA was consumers being locked into paying billions above market prices. PECO agrees with EAP that the solar AEC market is over-supplied and that solar AEC prices have sharply declined over the past two to three years. PECO states that, a few years ago, solar AECs were trading on the short-term market for over $250 and are now trading for $10. Therefore, long-term contracts entered into a few years ago are significantly over market price. PECO contends that, if the contracts were mandated on utilities, consumers would be locked into above market prices. Conversely PECO states that long-term contracts negotiated by the competitive suppliers place the risk on the shareholders. PECO at 21 and 22.

PECO declares that AECs are inherently a part of the supply of electricity and should remain with the LSE. Further supporting this point, PECO refers to the PECO and FE default service plan proceedings, where the Commission ruled that Generation Deactivation Charges were determined to be "inherently part of the supply of electricity and should remain with the EGSs." PECO at 22.

As to long-term, subsidized AEC contracts, PECO avers that such contracts will deter competitive investment in renewable generation. PECO states that there is currently an oversupply of renewable generation and there will continue to be an oversupply through at least 2015, as evidenced by the Commission's 2011 AEPS Annual Report. PECO further explains that the data on pages 20 and 22 of the 2011 AEPS Annual Report show that the Tier I and the solar supplies are in excess of the projected demand in 2015 and suggests an additional year of excess. Additionally, PECO submits that AECs can generally be banked in all state renewable portfolios programs in PJM, therefore pushing the oversupply out another two years. Further, PECO claims that, since the publishing of the 2011 AEPS Annual Report, installed wind capacity has increased from 5,800 to 6,300 MW and solar photovoltaic MW have almost doubled. With this information, PECO contends that the market is oversupplied until at least 2017. PECO at 23.

PECO goes on to explain that the oversupply of renewable resources was caused, in part, by state and federal subsidies, despite a lack of demand. Renewable projects are more expensive than current energy and capacity prices and, therefore, rely on the value of AECs and other renewable energy credits (RECs) for development. PECO claims that interfering in the AEC market only exacerbates the oversupply of qualifying resources keeping AEC prices artificially low and, in turn, devalues the investment made by merchant developers of existing renewable generation. PECO at 24 and 25.

PECO requests the Commission to resist the urge to "fix" a nonexistent problem and let the market work as intended. It contends that, as the oversupply of existing renewable energy resources is reduced by increasing AEPS demand, the AEC prices will respond accordingly. PECO at 25.

PECO, as well as EPGA, note the comments of the Commission at the Federal Energy Regulatory Commission (FERC) addressing the potential anti-competitive results of New Jersey and Maryland's proposals for subsidized long-term contracts for new natural gas generation. PECO at 26. The Commission noted, in its comments, that Pennsylvania has "abandoned direct command and control regulation...in favor of a market based approach which relies on economic signal to "tell" potential investors when, where, and how to add generation capacity." Finally, PECO cites the Commission's summary of the ultimate harm of subsidized generation:

> In the short run, there may be savings achieved by paying

> subsidized prices to a subset of suppliers, and lower prices to the rest. But in the long run, consumers will pay more, up to and including losing the benefits of competitive markets...This is not in the public interest.

PECO at 27.

Lastly, PECO opines that long-term, subsidized AEC contracts impede competitive retail markets. PECO maintains that many EGSs have made significant investments (including renewable energy investments) in order to competitively serve their customers. It specifically points to Exelon Generation and Constellation wind and solar generation investments. PECO opines that those investments were made with the expectation that, as LSEs, they would have ongoing AEPS obligations and an opportunity to sell renewable energy and resulting AECs in the market at competitive prices. PECO opposes any scenario that does not involve the LSE being fully responsible for competitively procuring all energy for its customers. PECO at 27.

FES is closely aligned with PECO in that they believe the procurement of long-term AEC contracts should be the responsibility of EGSs, not EDCs. FES urges the Commission not to pursue legal authority to use the EDC, or DSP, to incent new construction of generation. FES states that, presently, the DSP has the sole discretion to determine the generation source and fuel type for its long-term contracts. FES opines that removing this discretion potentially leads to a harmful scenario of entering into long-term contracts at above-market prices to encourage new construction. It believes that the Commission's proposal is contrary to the Competition Act. FES at 10 and 11.

NRG supports the continuation of EDCs entering into long-term contracts for, and the allocation and cost recovery of, solar AECs. However, NRG generally opposes the requirement that EDCS procure long-term non-solar AEC contracts. NRG believes that EGSs are best suited to competitively procure alternative energy resources to meet their AEPS obligations and the needs of their customers. NRG contends that, if EDCs are to undertake this procedure, EGSs may face challenges in providing offers that are 100 percent renewable. NRG at 14.

EPGA generally opposes the Commission's proposal concerning long-term AEPS contracts. EPGA believes that the Commission's proposal will result in a distortion of the wholesale markets by arriving at a price for these contracts that is substantially different from a price that a market would achieve under conditions of perfect competition. EPGA at 4. EPGA contends that the allowance of this subsidy is discriminatory towards non-AEPS-qualified generation resources which must compete without the benefits of a Commission-sponsored financial risk mitigation plan. Additionally, EPGA argues that mitigating long-term cash flow risks for AEPS-qualified generation is contrary to the Competition Act. EPGA at 4.

EPGA contends that current and projected capacity are adequate. EPGA cites the 2011 AEPS Annual Report and PJM's Generation Attribute Tracking System (GATS) to validate their argument. EPGA at 9 and 12.

Finally, EPGA alleges that the Commission lacks statutory authority for its proposed market interventions. EPGA cites the Commission's responsibilities under Act 213 of 2004, enumerated 1 through 19. They go on to assert 66 Pa.C.S. § 2807(e)(3.2)(iii) states that "the default service provider shall have sole discretion to determine the source and fuel type." EPGA at 13-16.

EPSA opposes the Commission's proposal. In general, EPSA states that the Commission's proposal would be anti-competitive in Pennsylvania's retail markets and would hurt the marketplace if Pennsylvania policy was extended or expanded to other resources by policy makers in other states. Secondly, EPSA opines that there is adequate renewable generation in PJM to meet Pennsylvania's AEPS requirements through at least the next three years. EPSA at 2-5.

P3 specifically opposes the Commission's proposal which would help facilitate a successful build-out of AEPS-qualified generation facilities by mitigating long-term cash flow risks for relevant generation owners or financiers. P3 argues that this proposal is anti-competitive and leads to long-term contracts that are uneconomic. P3 states that there is no evidence in this record, or otherwise, that suggests the competitive market will not work to send proper price signals for energy, capacity and AECs when renewable generation is needed. P3 contends that renewable generation already has an advantage over traditional forms of generation because of the legislatively-mandated AEPS requirements. P3 at 4.

2. Resolution

Given the multitude of comments in opposition, the Commission, at this time, will not adopt a prescriptive AEC procurement methodology. Rather, we believe that this subject would be more appropriately addressed by the Legislature, if they so desire.

N. Statewide Consumer Education Campaign

In its *Tentative Order*, the Commission proposed the development and implementation of a comprehensive statewide consumer education campaign (campaign) based, in part, on the input of stakeholders participating in the RMI consumer education subgroup.

The proposed campaign, estimated to cost $5 million per year, for at least three years, would have required both EGSs and EDCs to contribute to the campaign following the "Fair Share" approach offered by EGSs during the subgroup process. The campaign's primary message would focus on educating electricity consumers about the benefits of electric shopping and using the Commission's online shopping and comparison tool, www.PAPowerSwitch.com. Secondary messages would educate consumers about other RMI actions. *Tentative Order* at 37-39.

1. Comments

Throughout this Investigation, nearly all stakeholders have consistently supported the Commission's efforts to enhance consumer education, including the initiatives undertaken as part of the Commission's December 15, 2011 Secretarial Letter[31] and the *March 2 Order*. However, comments to the *Tentative Order* reflect the lack of a clear consensus among stakeholders in moving forward with the proposed campaign.

RESA comments that the proposed plan is too large in scope, and believes that much of the work done up to this point can easily be reused. RESA at 25-32. FES makes the argument that marketing and consumer education aimed at particular customer classes, or at customers in individual EDC service territories, should be left to the discretion of, and funded by, individual EGSs as part of their competitive strategies and not part of a directed statewide campaign. FES at 11-15.

The Commission's proposed funding mechanism for the campaign, the "Fair Share" approach described in the *Tentative Order*, also did not generate a clear consensus. DLC, PPL and Verdigris support EGSs paying all or a majority of the costs associated with the campaign. DLC at 1 and 10; PPL at 32 and 33; Verdigris at 5. On the other hand, FES points out that the Commission's 2007 Final Order (*Policies to Mitigate Potential Electricity Price Increases*, Docket No. M-00061957 (Order entered May 17, 2007)) did not propose that EGSs bear any costs for consumer education, and,

[31] *Investigation of Pennsylvania's Retail Electricity Market; Directive to Specified Electric Distribution Companies to Produce and Mail Electric Shopping Postcards to Customers,* Docket No. I-2011-2237952. Secretarial Letter dated December 15, 2011.

furthermore, the Commission may lack statutory authority to impose these costs on EGSs. FES at 11-15.

Additionally, several EDCs recognize that EDCs may still have consumer education obligations under the new campaign and, therefore, should be able to not only continue conducting current consumer education efforts in their service territories (DLC and PPL), but also recover costs incurred for consumer education (DLC, PPL, PECO and FE). DLC at 1 and 10; PPL at 32 and 33; PECO at 28 and 29; FE at 14 and 15.

Along the same lines, FE, NEM, OCA, PEMC and RESA feel strongly that consumer education benefits all customers and, therefore, the cost of the campaign should be included in the EDC delivery rates as a non-bypassable charge. FE at 14 and 15; NEM at 10; OCA at 23-25; PEMC at 9 and 10; RESA at 25-32. RESA elaborates that, under the currently-proposed "Fair Share" approach, it is the shopping customers who are penalized by bearing a majority of the costs for the campaign. RESA at 25-32. Finally, the Industrials agree with the Commission that only residential and small C&I customers should pay for the consumer education campaign, as the campaign would be conducted primarily for their benefit. Industrials at 13.

2. Resolution

After reviewing the comments of the parties to the *Tentative Order*, the Commission has decided to reduce the size and scope of the campaign.

The EDCs' existing consumer education plans, pursuant to the Commission's *Policies to Mitigate Potential Electricity Price Increases* Final Order, Docket No. M 00061957, entered May 17, 2007, expired in 2012 and will not be renewed. The Commission directs any EDCs which may continue to have Commission-approved consumer education obligations to coordinate those obligations with the messages of this statewide campaign to ensure consistency.

The Commission will direct its Office of Communications to work with a vendor, which the Commission will select, to develop, a detailed plan for a statewide consumer education campaign for the Commission's consideration. The campaign will be funded directly by those EDCs that currently have competitive offers in their service territories, with a total aggregate funding not to exceed $2 million. The funding allocation will be based on their total number of residential and small commercial customers, both shopping and non-shopping, and recovered from those customers through a non-bypassable surcharge.

Furthermore, the Commission strongly encourages, and fully expects, those EGSs who are active in Pennsylvania to make significant contributions of funding and other resources to this campaign, which will be a part of the maximum $2 million total for the campaign and will help to offset the costs to the EDCs and their customers. The allocation of the $2 million total aggregate funding for EDCs will not be determined or instituted until after there is a clear understanding of the level and type of participation volunteered by EGSs.

The Commission directs its Office of Communications to work with RESA, the American Coalition of Competitive Energy Suppliers (ACCES), NEM and their respective members, to secure partnerships and commitments to this campaign and to participate in campaign activities, such as consumer incentive contests.

The campaign will launch by June 2014.

The campaign's primary message will focus on educating consumers about the benefits of electric shopping and referring customers to www.PAPowerSwitch.com, to shop, to switch or to become informed. Additionally, the education campaign will inform consumers of "typical" contract terms and conditions. The Commission directs its Office of Communications to contact the Commonwealth's statutory advocates, PULP and the Commission's Consumer Advisory Council to identify possible issues and concerns with EGS contracts.

The primary audience of the proposed campaign will be residential and small business customers. The initiative will include customer surveys, advertising, consumer incentive contests and other educational initiatives.

The Commission will also work proactively with the National Federation of Independent Businesses, PA Chamber, and trade and civic organizations to promote www.PAPowerSwitch.com, this campaign and its messages.

O. Regulatory Costs and Assessments

1. Annual Electric Generation Supplier Licensing Fee

In its *Tentative Order*, the Commission proposed that EGSs pay an annual licensing fee to the Commission. This annual fee would help defray Commission costs associated with the following tasks that staff undertakes with respect to EGSs: review of reports, oversight of regulatory compliance issues including consumer complaints, maintenance of and upgrades to www.PAPowerSwitch.com and review of EGS bonding requirements. Many of these tasks involve not only suppliers that take title to electricity, but also brokers and marketers. *Tentative Order* at 40.

We also recognized in our *Tentative Order* that the Commission is prohibited from levying assessments on EGSs[32] and a one-time licensing fee in the amount of $350 is the sole funding that the Commission presently receives from EGSs.[33] Given the amount of work performed, and time spent, on EGS-related issues, combined with the small sum that licensed EGSs currently pay to the Commission, we proposed an annual fee. We presented two options on how to structure the fee: (1) a fee that is based on a percentage of an EGS' gross intrastate revenues, subject to a maximum cap;[34] or (2) a flat annual fee of $1,000. We proposed including brokers and marketers, as well as EGSs taking title to electricity, in the obligation to pay the annual fee. We recommended that EGSs that do not take title to electricity and are not liable for gross receipts tax, such as brokers and marketers, pay a flat annual fee of $1,000. *Tentative Order* at 40-41.

a. Comments

The majority of stakeholders who commented on this issue agree that the Commission should impose an annual fee. Several parties, such as NEM, PECO, PPL and RESA, prefer a flat annual fee over a fee that is based on a percentage of EGS sales, provided that the amount of the fee reasonably reflects Commission costs and is capped at an amount that does not create a barrier for EGSs to enter the market. NEM at 11; PECO at 29; PPL at 34; RESA at 32-34. PULP asserts that the $1,000 flat fee is a trivial sum and suggests that the Commission increase the fee. PULP at 19.

Other stakeholders, such as NRG, PEMC and WGES, recommend that the Commission impose a fee that is based on a percentage of sales. NRG at 15; PEMC at 10

[32] *See, Delmarva Power & Light Co. v. Commonwealth*, 870 A.2d 901, 911 (Pa. 2005).
[33] The Commission charges a $350 application fee for an EGS license pursuant to section 317(a)(4) of the Code, 66 Pa. C.S. § 317(a)(4), and section 1.43(a) of the Commission's regulations, 52 Pa. Code § 1.43(a).
[34] We noted that EGS intrastate revenues can be obtained from reports pertaining to gross receipts that EGSs are required to file with the Commission pursuant to 52 Pa. Code § 54.39.

and 11; WGES at 3 and 4. These stakeholders agree that the amount of the annual fee should be capped so as not to create a barrier to enter the market and that it should reflect Commission costs. If the Commission uses the fee structure based on a percentage of EGS sales, then OCA and WGES recommend that the Commission also impose a minimum annual fee, given that every EGS generates costs for the Commission and an EGS without sales in a certain year would be exempt from the annual fee. OCA at 25 and 26; WGES at 3 and 4.

PPL suggests that the annual fee be used towards consumer education purposes. PPL recognizes that allocating the fee for this purpose may necessitate legislative changes. PPL at 34.

On the other hand, some stakeholders disagree with the Commission's imposition of an annual administrative fee on EGSs. FES argues that the Commission's institution of an annual fee on EGSs requires a revision to the Code. FES notes that Section 317(a) of the Code, 66 Pa. C.S. § 317(a), permits the Commission to charge fees for certain services, including copying and certifying paper, testimony and records, and processing filings such as securities certificates and applications. However, Section 317(a) does not appear to permit the assessment of an annual fee upon EGSs. FES suggests that if statutory authority is obtained to impose an annual fee on EGSs, that the fee amount be established on a "reasonable costs basis," pursuant to 66 Pa. C.S. § 317(a), and shared equally by all licensed EGSs. FES at 15 and 16.

RESA notes that EGS customers already pay Commission costs through EDC assessments and, therefore, there is no need to separately assess EGSs. RESA at 32-34.

Verdigris pleads that the Commission exempt brokers and marketers from the annual fee and states that the cost of overseeing brokers and marketers is negligible. If brokers and marketers are not exempted from the fee, then Verdigris suggests that they pay a licensing fee based on a percentage of revenues. Verdigris at 1-5.

b. Resolution

At the outset, the Commission agrees that legislative changes are necessary in order to impose an annual fee on EGSs, as mentioned by FES. The Commission proposes to seek to amend Section 317(a) of the Code to permit the Commission to establish, by a rulemaking, reasonable fees to be charged and collected for other services that are not currently enumerated in Section 317(a). The Commission expects to pursue this legislative change in order to lawfully collect fees from EGSs to reimburse the Commission for employee time and resources spent on supplier-related matters. At this time, the Commission does not envision using the annual EGS fee for consumer education, as suggested by PPL.

After the Code is amended, the Commission intends to require all EGSs, including brokers and marketers, to pay an annual flat fee in the amount of $1,000. The Commission believes that a flat fee structure is the easiest for the Commission to administer and suppliers to anticipate. Further, upon considering comments from the majority of stakeholders, a $1,000 annual fee does not appear to be so expensive that it would act as a barrier for new EGSs to enter the Pennsylvania market or existing licensed EGSs to remain in Pennsylvania.

The Commission disagrees with Verdigris that the cost of overseeing brokers and marketers is negligible. The Commission notes that brokers and marketers are listed on www.PAPowerSwitch.com, a website for which the Commission must pay to update and maintain. In addition, the Commission is tasked with overseeing compliance with its regulations set forth in Chapter 54 of the Pennsylvania Code, 52 Pa. Code §§ 54.1, *et seq.*, "Brokers, marketers, aggregators or any other entities, that sell to end-use customers electricity or related services utilizing the jurisdictional transmission and distribution facilities of an EDC" are required to abide by the Commission's regulations in this chapter unless they are expressly excluded. *See* 52 Pa. Code § 54.31, relating to Definition of EGS. Thus, the Commission expends considerable staff time and resources on EGSs, including brokers and marketers, and the Commission maintains that an annual fee, payable by all EGSs, is essential to defray costs related to EGSs.

2. Recovery of Electric Industry Assessments through an Automatic Surcharge Mechanism

In its *Tentative Order*, the Commission proposed seeking legislative changes to permit EDCs to use an automatic surcharge mechanism, such as that which is available for the recovery of state taxes in Section 1307(g.1) of the Code, 66 Pa. C.S. § 1307(g.1), to recover electric industry assessments paid to the Commission. We noted that the Commission collects all regulatory expenses associated with the electric industry from EDCs. While EDCs may seek recovery of assessments through their distribution charges as part of a base rate case, the Commission believes that it would be more equitable to permit EDCs to recover assessments through an automatic surcharge mechanism. In this manner, EDCs would be able to fully recover assessments, which represent an unavoidable expense that is incurred by the Commission to regulate the electric industry – including EGSs – and also would be required to pass-through any reductions in assessments to consumers. *Tentative Order* at 41-42.

a. Comments

Several stakeholders support the Commission's initiative to seek legislative changes that would permit EDCs to recover assessments through a surcharge mechanism. These stakeholders, DLC, FE and PECO, remark that EDCs have traditionally recovered this expense in distribution charges that are established in base rate cases. DLC at 1 and

10; FE at 15; PECO at 29 and 30. However, the annual amount of this unavoidable expense has fluctuated and use of a surcharge mechanism will result in a fairer recovery. DLC recommends that the Commission provide EDCs with the flexibility to implement the adjustment clause in either the next base rate filing or by a separate filing. DLC at 10.

Three stakeholders oppose the Commission's proposal: Citizens' and Wellsboro, the Industrials and OCA. Citizens' and Wellsboro argues that the costs to regulate EGSs should be solely the expense of EGSs. Citizens' and Wellsboro at 10. Likewise, the Industrials assert that the Commission's assessments should be allocated to the entities that are responsible for them – the EGSs. The Industrials question why the Commission is not seeking to amend the Code to give it authority to directly assess EGSs. Industrials at 13-15.

OCA submits that Commission assessments are not large or volatile expenses that require special ratemaking treatment. Rather, assessments are a normal recurring operating expense that are appropriately included in base rates and no legal or policy justification exists to single-out this one item for surcharge treatment. OCA at 26.

The Industrials also support retaining assessments in base rates and note that EDCs can file base rate cases to reflect the level of assessments. The Industrials remark that some EDCs file base rate cases every 2 to 3 years. If the Commission chooses to implement an automatic surcharge mechanism, the Industrials recommend that the clause be designed to reflect the allocation methodology for regulatory assessments that is used in rate cases. The Industrials assert that a clause that results in a per-meter surcharge or a percentage of the customer's distribution costs, such as the State Tax Adjustment Surcharge, would be more appropriate than a kWh surcharge. Industrials at 13-15.

Citizens' and Wellsboro argue that the recovery of EGS assessments through an automatic surcharge mechanism penalizes customers who do not shop in the retail market. Citizens' and Wellsboro claim that it is not reasonable to require customers who do not use EGS services to subsidize EGS regulatory costs. Citizens' and Wellsboro at 10.

b. Resolution

The Commission intends to pursue legislative changes to allow EDCs the option to implement an automatic surcharge mechanism to recover electric industry assessments paid to the Commission. When the Code is revised, the Commission anticipates providing EDCs with flexibility to decide whether, and how, they would like to implement the adjustment clause, such as by including it in a base rate filing or by a separate filing. The Commission will address the appropriate allocation methodology for assessments after the Code is amended.

In response to Citizens' and Wellsboro's concerns that the automatic surcharge mechanism penalizes customers who do not choose an EGS, the Commission notes that electricity customers will not fare worse than the current method of EDC recovery of electric industry assessments in base rates. Rather, the surcharge mechanism will result in a fairer recovery to the EDCs, who must pay for all electric industry assessments, and will not adversely affect electricity customers.

As to the Industrials' question asking why the Commission is not seeking an amendment of the Code to allow assessments on EGSs, the Commission believes that the better solution is to continue collecting all costs associated with regulating the electric industry from EDCs and allowing EDCs to recover those assessments through an automatic surcharge mechanism. Our reasons are explained below.

Initially, we note that it would often be difficult for Commission staff to determine proper time allocations as between EDC and EGS industry groups. For instance, although time spent on an EDC's base rate case would clearly be allocated to the EDC industry group and time spent an EGS's license application would be allocated to the EGS industry group, it would be challenging for staff, with any accuracy, to allocate time spent on this Final Order or on a default service plan order on either the EDC or EGS industry group. Since many of the proceedings and issues affect both EDCs and EGSs, it is more efficient to simply allocate all time spent on electric issues to the same category. Additionally, assessing only EDCs is simpler from an administrative standpoint since that process involves the issuance of assessment notices to ten companies rather than 230 companies. Further, assessing only the EDCs provides greater certainty for the source of revenues needed to fund the Commission's budget due to their presence in Pennsylvania as the delivery companies. Finally, assessing EGSs could be viewed as anti-competitive since EDCs recover these costs through the distribution charge while EGSs would only have the commodity charge available for recovery.

CONCLUSION

For the above-described reasons, the Commission adopts the end state model for default electric service as described herein.

THEREFORE,

IT IS ORDERED:

1. That the End State of Default Service, as set forth in this Final Order, is adopted.

2. That the Office of Competitive Markets Oversight shall convene a working group to identify issues related to the implementation of a model in which an alternative entity, or multiple entities, provides default service. Recommended

solutions for these issues shall be provided to the Commission no later than November 15, 2013.

3. That the Office of Competitive Markets Oversight shall develop a Procurement Collaboration Working Group which will formulate a uniform yearly certification process, a uniform supply master agreement and a procurement methodology and timeline for the electric distribution companies' quarterly default service auctions. This working group will also develop any other necessary protocols, procedures or documents necessary to run the quarterly auctions. The working group will provide recommendations to the Commission as soon as practicable, but not later than April 1, 2014, in order to provide the Commission time to approve or amend the recommendations by June 1, 2014.

4. That the Office of Competitive Markets Oversight shall explore options to create a more supplier-oriented utility consolidated bill and provide recommendations to the Commission by the end of 2013.

5. That the electric distribution companies shall utilize their existing supplier-consultation processes to develop and submit plans to the Commission by the end of 2013 which allow the implementation of seamless moves in their service territories by June 1, 2015.

6. That the electric distribution companies shall utilize their existing supplier-consultation processes to develop and submit plans to the Commission by the end of 2013 which allow the implementation of instant connects in their service territories by June 1, 2015.

7. That the Office of Communications shall implement the statewide consumer education campaign as set forth in this Final Order. The campaign will target residential and small business customers and will include significant contributions from electric generation suppliers, as well as electric distribution companies, in further promoting the benefits of electric shopping, directing consumers to www.PAPowerSwitch.com and educating consumers about changes brought about by the Retail Markets Investigation.

8. That the Office of Communications shall secure partnerships with the key stakeholders identified in this Final Order in an effort to maximize resources and ensure appropriate levels of communication and coordination on a statewide basis.

9. That this Final Order shall be served on all Electric Distribution Companies, all licensed Electric Generation Suppliers, the Bureau of Investigation and Enforcement, the Office of Administrative Law Judge, the Office of Consumer Advocate, the Office of Small Business Advocate, the Energy Association of Pennsylvania, and all other parties who filed comments or testified in Phases I and/or II of the Retail Market Investigation.

10. That a copy of this Final Order shall be filed at Docket No. I-2011-2237952 and posted on the Commission's website at the Retail Markets Investigation web page: http://www.puc.state.pa.us/utility_industry/electricity/retail_markets_investigation.aspx.

11. That the Office of Competitive Markets Oversight shall electronically send a copy of this Final Order to all persons on the contact list for the Committee

Handling Activities for Retail Growth in Electricity, and to all persons on its contact list for the *Investigation of Pennsylvania's Retail Electricity Market.*

12. That the Secretary close this docket upon the entry of this Final Order.

BY THE COMMISSION,

Rosemary Chiavetta
Secretary

(SEAL)

ORDER ADOPTED: February 14, 2013

ORDER ENTERED: February 15, 2013

A4

IR 13-020

Public Service Company of New Hampshire

Report on Investigation into Market Conditions, Default Service Rate, Generation Ownership and Impacts on the Competitive Electricity Market

Jointly Prepared by:

Staff of the New Hampshire Public Utilities Commission

and

The Liberty Consulting Group

June 7, 2013

Contents

Executive Summary

Bringing the state's electricity rates down to regional levels comprised a major goal of restructuring in the late 1990s. The legislature, the New Hampshire Public Utilities Commission (Commission), and the overwhelming number of stakeholders involved in restructuring saw the fossil and hydro resources of Public Service Company of New Hampshire's (PSNH) as a major asset in achieving that goal. A little over a decade later, those resources, taken as a whole, have gone from saving customers money to costing them significantly, relative to available market alternatives. One measure of the gap that now exists is to measure the difference between PSNH's default service rate, 9.5 cents per kilowatt-hour (kWh), and prevailing retail market prices, 7.0 – 8.0 cents per kWh, which are lower than PSNH's rate by approximately 15 to 25 percent.

In light of the current situation, on January 18, 2013, the Commission opened an investigation, to be performed by Commission Staff (Staff), to review market conditions affecting the default service rates of PSNH in the near term and how PSNH proposes to maintain safe and reliable service to its default service customers at just and reasonable rates. In addition, the investigation was to explore the impact on the competitive electric market in New Hampshire of PSNH's continued ownership and operation of generation facilities. To assist in its investigation, Staff retained the services of The Liberty Consulting Group, a consulting firm with experience with electric industry restructuring in New Hampshire, particularly in PSNH's service territory and with current experience in Northeast natural gas and energy markets. The investigation over the last few months involved obtaining information from PSNH and meetings with various stakeholder groups to elicit various viewpoints on the status of PSNH's default service rate and generation ownership both today and looking forward.[1]

In summary, the situation looks to worsen, as continuing migration from PSNH's default service by customers causes an upward rate trend. We find no supportable basis for optimism that future market conditions will reverse this unsustainable trend, especially in the near term. To the contrary, the PSNH fossil units face uncertainties that combine to create a risk of further, potentially substantial increases in costs.

At first glance, one option is to allow the current situation to continue, on the premise that the sizeable gap between default service and market prices would induce increasing levels of migration, and with the premise that default service is simply meant to be a safety net. If this were true, it would save customers money and help competitive suppliers build a long-term foundation for competitive choice. We found competitive retail suppliers, however, far less interested in the "headroom" created by the significant gap between market and PSNH's default prices, as compared with supporting a market that is conducive to competition over the longer term. Their interests focus more on a market that operates under a stable policy framework and rules. Their concerns about PSNH focus less on current default service prices and more on the

[1] Staff would like to take this opportunity to thank PSNH and all of the stakeholder groups for their cooperation and assistance throughout this investigation.

institutional barriers created by the presence of the distribution company in the energy portion of the business.

Wholesale suppliers, whose interests are overlapping, but not identical to those of retail suppliers, also focus on competitiveness issues (such as what incentives full cost recovery creates for PSNH in bidding its units into the market through ISO New England). We found consensus between them that the best approach from a market perspective would be to remove PSNH from the energy supply business, with PSNH remaining as a provider of electric distribution and transmission services, and establish a prompt and effective transition path that would permit third-party wholesale and retail providers to bring market-based rates to all of New Hampshire's residents and businesses.

Those we consulted who speak for customers (both large and small) share this view. None expressed the view that continuing default service rates at a substantial above-market price represented an appropriate option. The environmental groups with whom we met did not favor this option either. Some states have promoted a gap between their equivalents to default service and market prices to induce switching. None that we know of, however, support such a sizeable gap or the prospect of its steadily increasing economic burden on those end users who have not chosen to move from PSNH as their energy supplier.

Taking no action threatens to leave a dwindling yet still substantial number of the state's residents and small businesses facing ever higher costs for service relative to market alternatives and could eventually threaten the financial health of PSNH. Setting PSNH's default service rates closer to market rates and opening a proceeding to address recovery of deferred costs could provide short-term relief. Nonetheless, simple deferral of recovery is ultimately likely to do no more than postpone the burden that over-market costs represent. PSNH does not appear to have the ability to significantly reduce those costs without potential financial consequences to the company. Cost reductions could be attained through existing Commission authority; however, legislative action may also be required.

Securitization[2] represents one possible measure. It has the potential for producing a large reduction in the capital cost component of default service rates. Our analysis, using current market conditions[3], demonstrates that, under a wide range of assumptions, a post-divestiture combination of (a) market-procured power plus (b) costs for amortizing uneconomic ("stranded"[4]) costs may very well produce total costs less than what default service customers now pay. Considering the very strong likelihood that the gap between market and PSNH default service prices will increase over time, an option that would not only prevent growth in that gap, but actually reduce it, may prove a very powerful tool, albeit one that invites consideration of not just regulatory, but also statutory change. Spreading responsibility for stranded costs beyond default service customers would represent another such measure. Both approaches raise policy,

[2] Securitization is a process by which a utility creates a special purpose entity to issue bonds for the purpose of recovering stranded costs.

[3] Current market conditions involves current costs and forecasts but does not include environmental contingencies.

[4] Stranded costs can generally be defined as the difference between costs expected to be recovered under regulated rates and those recoverable in a competitive environment.

legislative, and potential litigation issues that call for engagement with stakeholders and the legislature in what we would anticipate to be complex and controversial processes.

There is not a great deal of time for the State to act to address what will become an increasingly onerous burden for what now comprises a majority of the state's residents and many of its smaller businesses. If it were determined that PSNH should exit the energy supply business, some of the options for facilitating that exit would take substantial effort.

Divestiture is one of those options. It can take the form of a public, competitive sale or a transfer of generation assets to a PSNH affiliate at a determined price, such as net book value. Either option would require a means for addressing the difference between the sale or transfer price and book value. PSNH has very recently observed that natural gas prices may soon reach levels that would make the PSNH fossil units market competitive. If PSNH is correct, then one would expect the fossil/hydro fleet as a whole to generate more than book value, particularly given that recent sale prices and preliminary indications from market participants show that the hydro units have value substantially in excess of their book cost.

We, however, do not share the view of PSNH, nor has the company in response to our requests provided any analysis confirming its view of fossil fleet value. Our analysis shows that the fossil units have very little market value. The detailed analyses that potential buyers would perform were outside the scope of our assignment, but the preliminary work we did strongly supports the following observations:

- The fossil units have minimal economic value, far below the net book costs.
- The hydro units have economic value far in excess of their net book costs.
- Taken together, however, the fossil/hydro fleet has value substantially less than net book costs.

PSNH has also made the case that the fossil units, apart from whether they have net positive value, provide an important form of fuel diversity insurance. The company cites recent instances of natural gas price spikes in the New England region. Such price spikes (resulting from constraints in the regional pipeline system) present a serious challenge to the region's reliability and are unlikely to be resolved through additional pipeline expansion in the near-term. Nonetheless, even at the level that constraints have occurred recently, their frequency and severity have not served to give the PSNH fossil units enough of a boost to overcome their negative value. Further evidence that this insurance role is not viewed as viable comes from recent sales at low prices of New England fossil assets that operate similarly to those of PSNH. In addition, we find notable the failure of ISO-NE to assign value to coal as a source of fuel diversity, even though the issue of fuel diversity is a region-wide one. In fact, the ISO-NE's current interest in implementing a "pay-for-performance" program, if approved, will likely do little to enhance the "insurance value" of PSNH's fossil units.

Another reason undercutting the PSNH view of insurance value is that potential environmental rules create the possibility of substantial new capital investment and operating restrictions to be applied to the fossil units. The risk of cost increases from future environmental mandates is an additional and significant concern. This certainly was the view of the environmental groups with which we met. Their goals include the shutdown of the fossil units for environmental reasons, but the information they provided us was strongly rooted in cost considerations.

The fundamental difference in view of fossil fleet value between PSNH, on the one hand, and the overwhelming weight of stakeholder opinion, on the other hand, suggests an interesting alternative: a transfer of the fossil/hydro fleet to an affiliate at net book cost would enable PSNH's parent to gain value if its views of value are strongly held. Such a transfer would eliminate stranded costs as an issue, which is important, given the prevailing view that the fleet does not have positive economic value. The transfer would also eliminate contention over stranded cost sharing.

Many important questions remain to be answered. We believe that they require prompt answers, given the circumstances. The Commission should consider opening a proceeding to receive comments and recommendations from PSNH and other stakeholders regarding this report and the issues it addresses. Particular focuses should include the following:

- Whether PSNH's default service rate remains sustainable on a going forward basis
- What "just and reasonable" means and what it requires with respect to default service in the context of competitive retail markets
- Analytically supported views of the current and expected value of PSNH's generating units under an appropriately designed range of future circumstances.
- What means exist to mitigate and address stranded cost recovery

The valuations of PSNH units as described in this report are preliminary. They indicate a lack of competitiveness across a wide range of assumptions. However, definitively assessing the costs and benefits of some options depend on reasonably firm value estimates. Securing that firmness requires more work than our report entailed. The Commission thus may also want to consider requiring an independent asset valuation process undertaken at a more detailed level.

We also recommend that consultation with legislative and executive leadership begin. We recommend that PSNH bring forth immediately proposals that would address a transfer of energy supply assets to an affiliate in accord with the optimistic views that the company has expressed with regard to the value of those assets.

Abundant natural gas supply has played a large role in holding electricity market prices low since "fracking" caused no less than a seismic market shift several years ago. Tumultuous world markets and a strong impetus for LNG exports from North America cannot be ignored or consigned to the past. Neither we nor anyone else can guarantee what will happen with natural gas availability or pricing over the horizon that we can see from here. Nevertheless, over the period during which PSNH's default service will experience the continued increases that we project, there is a very high level of confidence that circumstances will not change enough to reverse the growing burden. PSNH has consistently expressed contrary views, including very recently, but no information it has provided to us support that view. Neither do reports of U.S. government agencies or other sources available to us addressing energy issues over the next five to ten years.

It is always possible that the energy world that emerges will differ from the one(s) we anticipate now. Nonetheless, the strong consensus (apart from PSNH) that exists supports our strong conviction that planning across this five to ten year period is not only appropriate, but can be performed with a sufficiently strong belief that the combined value of PSNH's fossil/hydro fleet is not likely to change dramatically.

There are no simple answers. In conducting our investigation, we looked to explore a range of alternatives while being mindful of potential financial impacts to PSNH. Each alternative path brings with it questions, potential challenges, and possible legislative hurdles. One thing that is clear, however, is that parties want certainty. Whether it be PSNH customers, retail or wholesale competitors, or other stakeholder groups, continued uncertainty with respect to PSNH's generation ownership and its role in the competitive market makes planning future electricity purchase and other business decisions difficult, if not impracticable. We view this report as providing valuable information and recommendations to be used by all interested parties as PSNH, its customers, other stakeholders, and the State of New Hampshire as a whole, look to forge a constructive path that is in the collective best interests.

Historical Background of Restructuring Efforts

This report was prepared pursuant to the Commission's Order of Notice, opening Investigative Docket No. IR 13-020, issued on January 18, 2013. The Commission endeavored to respond proactively to changing conditions in the retail and wholesale electricity markets. PSNH occupies a unique position in the State's electricity market, given its size and geographic reach. This posture has been largely shaped by legislative action since the beginning of what is termed "restructuring" of the New Hampshire electricity market. PSNH has not remained passive in responding to the challenges and opportunities presented by restructuring, but is alone among New Hampshire's incumbent utilities in continuing to maintain a fleet of generation assets.

Historically, the production of electrical energy and its distribution along a system of wires to end-use customers, was considered a "natural monopoly." Competition within a given electrical utility's service area was thought to be impossible, or at least economically wasteful. State legislatures came to accept the rationale for allowing vertically-integrated monopolies of electrical generation and distribution within a specific service area as necessary to stimulate private investors to take the risk of spending massive sums to provide the new technologies. These investments were encouraged by states through the granting of utility franchises to power companies, which provided a stable customer base from which investment costs, operating costs, and a rate of return could be recovered.

By the 1990's, important developments resurrected the potential for the introduction of market competition within electrical utilities' service territories. A new enthusiasm for consumer choice and free-market dynamism encouraged efforts to break up utility monopolies, first in telecommunications, then in electricity, with the hope that lower costs and better service would result from the entrance of competitors into these closed markets. In general terms, it became clear that the distribution of electricity, that is, the provision of electric current to end users through the wires of the power supply network, would remain a natural monopoly. However, the proponents of electric restructuring believed that the supply and generation of electrical power could be opened to competition, on both the retail and wholesale levels. At the national level, the 1992 Federal Energy Policy Act was instrumental in expanding competition within wholesale power markets, and the Federal Energy Regulatory Commission's 1996 Open Access Rule required all electric utilities to provide open, non-discriminatory use of their transmission systems.

New Hampshire restructuring efforts began in earnest in June 1995, with the passage of Senate Bill 168, which created the Retail Wheeling and Electric Utility Restructuring Study Committee to study the issues associated with allowing retail customers choice. The Commission was also charged with establishing a pilot program for competitive retail purchasing of electricity. Following the success of this program, the Legislature enacted House Bill 1392 in May 1996, which initially established the restructuring statutory scheme in RSA Chapter 374-F, and directed the Commission to develop a statewide electric restructuring plan.

This plan was issued by the Commission on February 28, 1997, was entitled "Restructuring New Hampshire's Electric Utility Industry: Final Plan." Under the plan, and pursuant to RSA 374-F:3, vertically integrated electric utilities, including PSNH, were to unbundle retail services into generation, transmission and distribution components. The Commission plan also required distribution utilities, including PSNH, to sever corporate ties between competitive (supply/generation) and non-competitive (distribution) components by divestiture. The Commission's plan also required distribution utilities to sell generation and marketing services and to sell off any rights to obtain power under existing purchase contracts. The Commission's plan also outlined an approach to "stranded costs." However, this approach would lead to protracted litigation with the electric utilities. These challenges led to broad changes to the original design of restructuring in New Hampshire.

Within days of the issuance of the Commission's plan for restructuring, the parent company of PSNH, Northeast Utilities, PSNH, and the other franchised investor-owned electric utilities in New Hampshire filed suit in federal court to block the Commission's plan. After four years of effort, restructuring for PSNH resulted from settlement negotiations with supporting Commission and Legislature action. The Agreement between PSNH and Governor Shaheen, filed with the Commission in August 1999, still contemplated the full sale of PSNH's generation assets and the concurrent issuance of rate reduction bonds. The Legislature endorsed the issuance of the rate reduction bonds, and required PSNH's divestiture of its interest in Seabrook Station by its enactment of Senate Bill 472/RSA Chapter 369-B in June 2000.

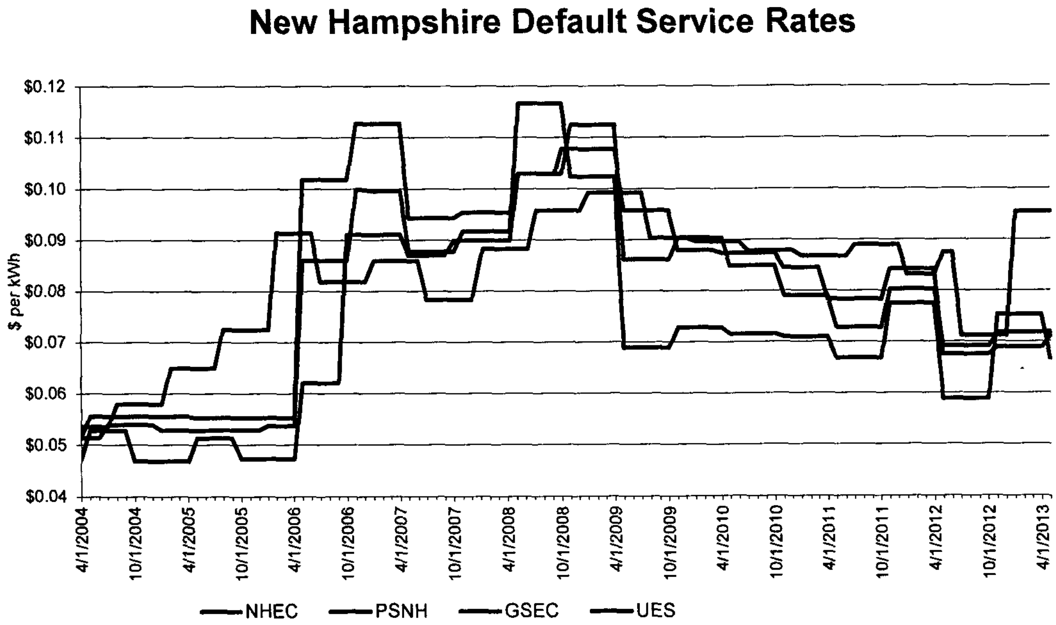
However, the Commission's, and Legislature's, original vision of a full divestiture of generation assets and supply business by the distribution utilities was scaled back. Most of these developments were in response to the 2000-2001 California energy crisis, in which the recently unbundled California electricity market had to contend with large price increases and repeated rolling blackouts. The concern stimulated by the California crisis led the Legislature to repeatedly delay the divestiture of PSNH's generation assets. In April 2001, the Legislature enacted House Bill 489, which amended the prior restructuring legislation to allow PSNH to provide transition supply service to customers until at least February 2006, as well as extending transition supply service for commercial and industrial customers until at least February 2005. House Bill 489 also allowed PSNH to keep its fossil-fueled and hydroelectric generation assets until at least February 2004 and to use them for the provision of supply service. PSNH divested only its interest in Seabrook Station, which went ahead as required by Senate Bill 472/RSA 369-B:3. The Legislature enacted RSA 369-B:3-a in April 2003, which provided that PSNH may not divest its fossil and hydro generating assets until April 30, 2006. RSA 369-B:3-a further provided that "...subsequent to April 30, 2006, PSNH may divest its generation assets if the [C]ommission finds that it is in the economic interest of retail customers of PSNH to do so, and provides for the cost recovery of such divestiture. Prior to any divestiture of its generation assets, PSNH may modify or retire such generation assets if the [C]ommission finds that it is in the public interest of retail customers of PSNH to do so, and provides for the cost recovery of such modification or retirement."

This is the statutory background for PSNH's current posture, in which PSNH faces increasing competitive pressure in its supply business, especially for commercial and industrial customers but also recently for residential and small commercial customers. PSNH has not elected to retire any of its major fossil-fueled or hydroelectric generating assets. As customer migration out of PSNH supply service continues to build, it places the burden of these assets' capital and operating costs on an ever-smaller customer base. From 2006 until roughly 2009, these pressures were mitigated by PSNH's relative market position as a low-cost supplier. The emergence of lower-cost supply competitors, relying largely on natural gas-fired generation, since 2009, however, have served to turn economic advantage to disadvantage when it comes to the PSNH generation assets.

Default Service Rates in New Hampshire

The Commission's order of notice stated that a major purpose of this investigation was to review "the market conditions affecting the default service of Public Service Company of New Hampshire (PSNH) in the near term and how PSNH proposes to maintain safe and reliable service to its default service customers at just and reasonable rates in light of those market conditions." Figure 1 below shows how PSNH's default service rate[5] has compared to the default service rates of other New Hampshire utilities since 2004[6]:

Figure 1: **New Hampshire Default Service Rates April 2004 – April 2013**



In comparing the default service rates charged by the various utilities, it is important to understand the difference between how PSNH's default service rate is calculated as compared to the other utilities. The New Hampshire Electric Cooperative (NHEC), Granite State Electric Company (GSEC) and Unitil Energy Systems (UES) have no generation assets and obtain supply for their default service load obligations by issuing requests for proposals (RFPs) and obtaining competitive bids from wholesale suppliers. PSNH, on the other hand, has an entirely different default service rate calculation paradigm—one that has a complex history and has evolved since the passage of Electric Utility Restructuring legislation[7] in 1996 as described above.

As stated, PSNH divested its entitlement to the power output from the Seabrook Station nuclear facility, but currently retains ownership of its fossil and hydro generating facilities. In addition,

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[5] PSNH's default service rate is identified in its rate tariff as "Default Energy Service Rate DE." References to PSNH's rate as "default service" or "energy service" are used interchangeably throughout this report but refer to the same rate.

[6] Prior to 2004, PSNH's default service rate was set at rates fixed by statute. See RSA 369-B:3, IV(1)(B)(i).

[7] See RSA 374-F, *Electric Utility Restructuring*, et seq.

PSNH also currently purchases energy, capacity and/or environmental attributes from other generating facilities, pursuant to contracts or rate orders. PSNH uses its generating facilities and entitlements, along with supplemental wholesale market purchases, as necessary, to fulfill the requirements of RSA 369-B:3, IV(b)(1)(A), which states,

> From competition day until the completion of the sale of PSNH's ownership interests in fossil and hydro generation assets located in New Hampshire, PSNH shall supply all, except as modified pursuant to RSA 374-F:3, V(f), transition service and default service offered in its retail electric service territory from its generation assets and, if necessary, through supplemental power purchases in a manner approved by the commission. The price of such default service shall be PSNH's actual, prudent, and reasonable costs of providing such power, as approved by the commission.

PSNH's default service rates are thus calculated by combining its costs of owning and operating its generation fleet with the costs of necessary supplemental purchases, including entitlements pursuant to power purchase agreements. This situation is what was referred to in the Commission's order of notice as the "hybrid" situation. PSNH's default service rates are initially determined on an annual basis effective at the beginning of a calendar year, with a review and adjustment of the rate effective mid-year.

It is clear from Figure 1 that a significant swing in market conditions evidenced itself in mid-2009. PSNH's default service rate had been consistently below the default service rates of the other New Hampshire electric utilities since 2006. In 2009, the situation reversed and, with only very short-term exceptions, PSNH's default service rate has exceeded the others' rates since mid-2009. Given the differences in how the default service rates are calculated among the utilities, the position of PSNH's default service rate in relation to the other New Hampshire utilities demonstrates that, due to changes in the fuel and energy markets, PSNH's generation fleet transitioned from being a consistently below-market cost source to an above-market cost source. Those changing market conditions have resulted in changes to both the operation of PSNH's generating facilities and power purchasing strategies. PSNH's "as necessary" supplemental purchases initially were primarily to cover load requirements not met by its generation fleet. In recent years, the supplemental purchases have also included market purchases at prices lower than PSNH's generation cost, thereby reflecting reduced operation of its generation fleet.

PSNH's Generation Fleet

PSNH owns and operates the following electric generating units (ratings in megawatts (MW)):

Table 1

Fossil Plants	Winter Rating	Summer Rating
Merrimack Unit 1 (coal)	108.0	108.0
Merrimack Unit 2 (coal)	330.5	330.0
Newington (oil/natural gas)	400.2	400.2
Schiller Unit 4 (coal/oil)	48.0	47.5
Schiller Unit 6 (coal/oil)	48.6	47.9
Combustion Turbines		
Merrimack CT 1 (jet fuel)	21.7	16.8
Merrimack CT 2 (jet fuel)	21.3	16.8
Schiller CT (jet fuel)	19.5	17.6
Lost Nation (jet fuel)	18.1	14.1
White Lake (jet fuel)	22.4	17.4
Biomass Plant		
Schiller Unit 5	42.6	43.1
Hydroelectric Plants		
Amoskeag	17.5	16.8
Ayers Island	9.1	8.5
Canaan	1.0	0.6
Eastman Falls	6.5	5.6
Garvins Falls/Hooksett	14.0	12.5
Gorham	2.1	2.0
Jackman	3.6	3.6
Smith	15.2	11.7
Totals	**1149.9**	**1120.7**

The plants have differing fuel sources, thus, their operations can be affected quite differently depending on events taking place in the fuel and electricity markets. Planning for the operation of the plants needs to, and does, take those differences into consideration. Planning with respect to short-term market activities is one aspect, but long-term considerations also need to be taken into account.

Least Cost Integrated Resource Planning

The January 18, 2013 Order of Notice that opened this investigation stated, in part,

> ...we find that certain portions of the Least Cost Energy Planning required by RSA 378:38 are best addressed in this investigation. Specifically, we find that RSA 378:38, III regarding assessment of supply options, and IX regarding assessment of the long- and short-term environmental, economic and energy price and supply impact on the State, should be addressed in this investigation rather than in PSNH's next least cost integrated resource plan.

Sections III and IX of RSA 378:38 were further addressed in the Commission's subsequent order regarding PSNH's most recent least cost integrated resource plan (Order No. 25,459 (January 29, 2013)):

> **C. Parameters for Next Full LCIRP Filing**
>
> We will now outline the expected parameters of the next full PSNH LCIRP filing, with specificity, to ensure clarity among PSNH, Staff, and other parties, regarding the future scope of the LCIRP process. These parameters relate to each of the elements of the LCIRP statute, RSA 378:38, I-IX. ...For Element III, an assessment of supply options, we require that PSNH will address the impact of the evolving electricity market in the ISO-New England system and on migration of their Default Service customers (giving special attention to migration data and trends for the most recent three years prior to the LCIRP filing date, and projections for the next three [to] four years, based on this recent data) on PSNH's generating units and other supply options...The final Element IX relates to an assessment of the plan's long- and short-term environmental, economic and energy price and supply impact on the State which, as noted by PSNH, can be difficult to discern, especially in light of the events of the past decade. With the change from a vertically integrated utility to one that provides a mix of market-based and owned generation, we are scaling back the time frame of the required planning period, to three years. But with the long lead time and expense to comply with many environmental mandates, we are also requiring a better assessment of the impact of those regulations that have been noticed in federal or state registers. To satisfy Element IX, we will require PSNH to present, as part of its next full LCIRP filing, its analysis of the LCIRP's impact on both long- and short-term environmental, economic and energy price and supply impact on the State.
>
> **D. Timing of Next LCIRP Filing, Waiver Pursuant to RSA 378:38-a**
>
> The recently-opened Commission investigation in Docket No. [IR] 13-020, regarding the market conditions affecting PSNH and its Default Service customers, and the impact, if any, of PSNH's ownership of generation on the New Hampshire competitive electric market, may address some of the parties' concerns in this LCIRP proceeding more directly. In order to avoid redundancies

> and resultant unnecessary administrative burden, we therefore waive, pursuant to RSA 378:38-a, PSNH's requirement to file a full LCIRP filing for the upcoming 2013 LCIRP round. However, as specified by RSA 378:38-a, PSNH must file, no later than September 3, 2013, its plans relating to transmission and distribution to satisfy its abbreviated 2013-round LCIRP filing requirements. (The recommendations outlined in Section C above should be viewed as guidelines for the development of the Company's next full LCIRP filing, which will be made subsequent to the resolution of the DE 13-020 investigation, and after PSNH's abbreviated 2013 LCIRP filing).[8]

The Commission waived the requirement for PSNH to file a *full* LCIRP in 2013, with the 2013 LCIRP to cover only transmission and distribution planning. With respect to PSNH's generation, supply options and the long- and short-term environmental, economic and energy price and supply impact on the State, it is apparent that the Commission determined that it would be much more instructive to use the results of this investigation to guide recommendations for future planning decisions. Thus, this report is not a substitute for PSNH reporting on its planning activities, as directed by the Commission.

Assessment of Supply Options and Long-Term and Short-Term Purchasing Alternatives

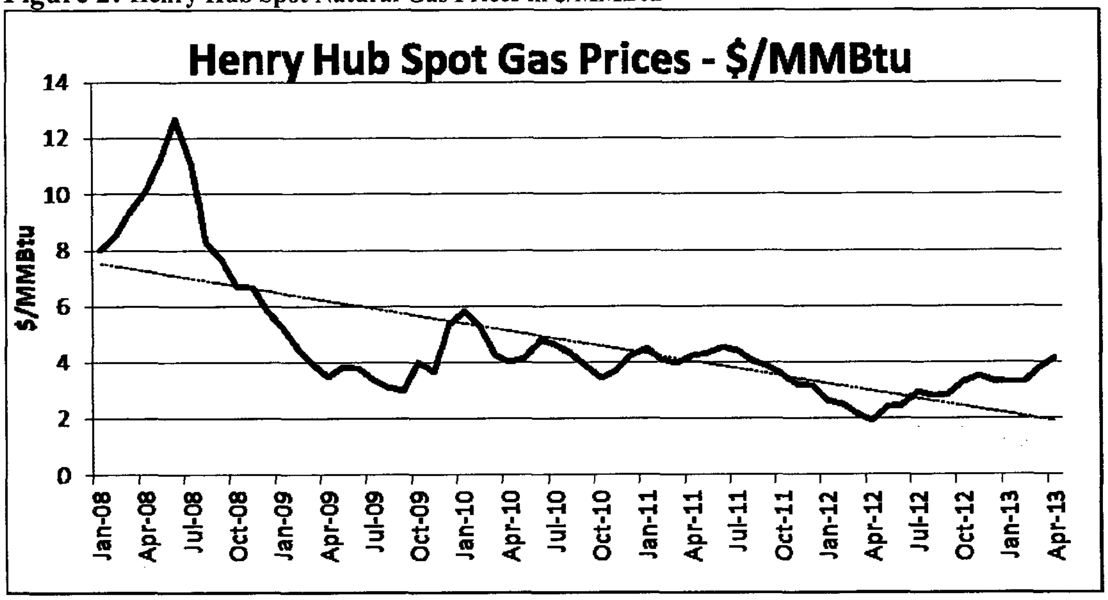
An assessment of PSNH's supply options and long-term and short-term purchasing alternatives for least cost planning purposes necessarily first involves an assessment of the status of PSNH's continued ownership and operation of generating facilities. To do so, it is important to understand the current position of PSNH's generating plants in the New England market as well as the near-term and long-term implications of changes in energy and fuel markets and other economic factors.

[8] Order No. 25,459 (January 29, 2013) at 19-21.

Energy Markets Outlook

North American energy markets have changed markedly over the last several years, driven in major part by a significant decrease in natural gas prices since 2008[9] (Figure 2). The chart displays the monthly average spot gas price at Henry Hub[10] in $ per million Btu and the linear trend line for this period. The effect of lower natural gas prices has been felt in every U.S. region, including the Northeast.

Figure 2: **Henry Hub Spot Natural Gas Prices in $/MMBtu**



Source: U.S. Energy *Information Administration*)

One important impact of these historically low gas prices is a reduction in wholesale electric power market prices (Figure 3). Figure 3 displays the average monthly wholesale energy price for ISO-NE's New Hampshire Zone[11]. The data represent the average of all hours (peak and off peak) for each month in the Day-Ahead Market. The overall trend (as displayed by the linear trend line on the chart) has been a reduction in energy prices, with the exception of January of 2013. This power price outlier reflects gas price spikes due to delivery constraints that were experienced during the winter of 2013.

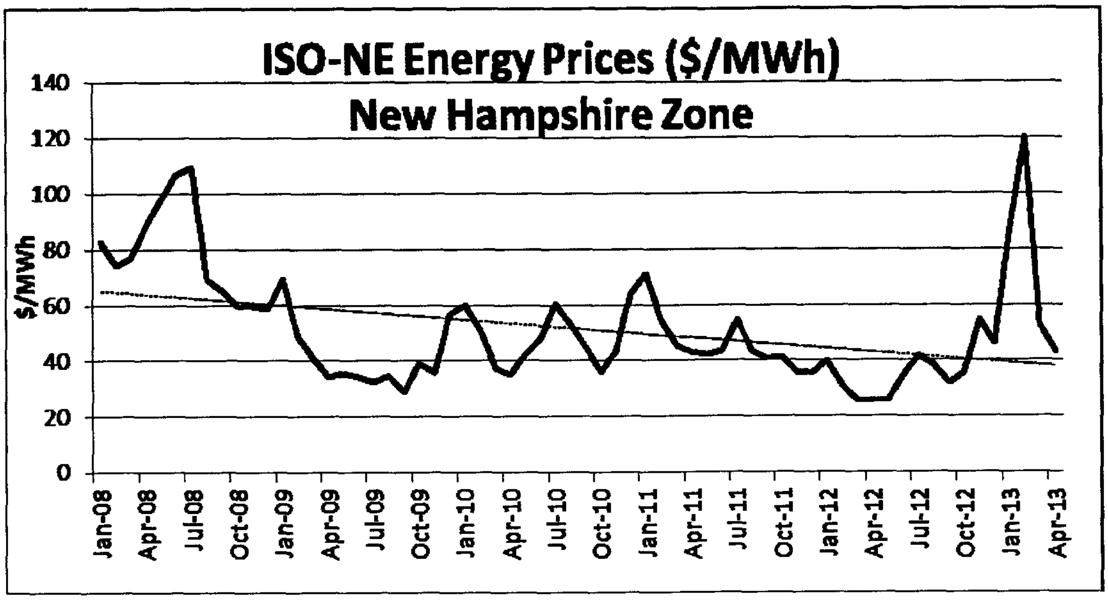
Natural gas prices affect all electric energy prices, but most directly affect peak energy prices. Gas-fired generation sets the price more frequently in peak periods. Therefore, the greatest impact of lower gas prices has been an overall reduction in what would be expected of peak energy prices, and to a lesser degree off-peak energy prices.

[9] U.S. Energy Information Administration.

[10] Henry Hub is a hub on the natural gas pipeline system used as a pricing point for natural gas futures contracts on the New York Mercantile Exchange (NYMEX).

[11] ISO-NE historical prices from www.iso-ne.com.

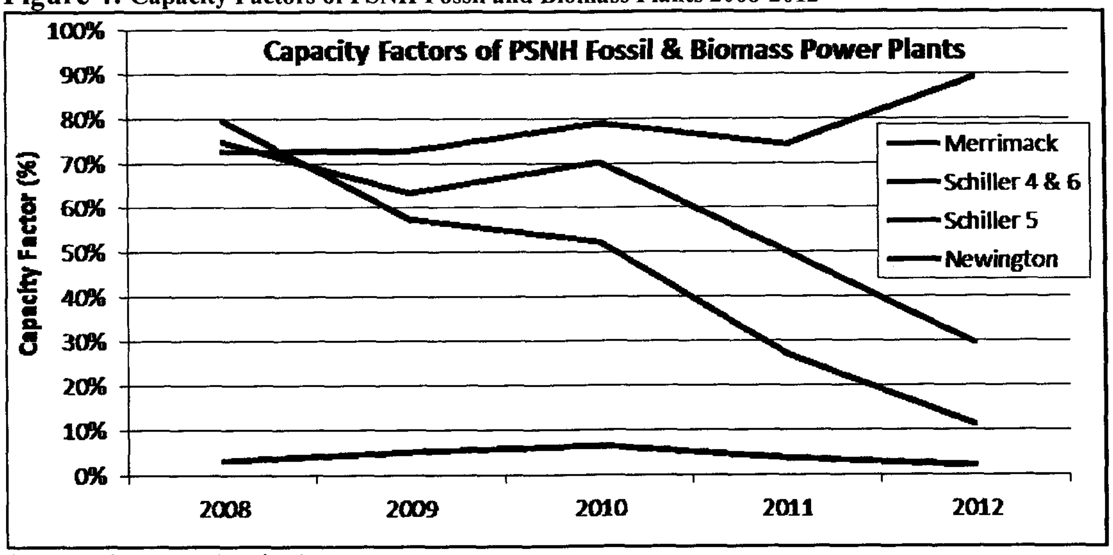
Figure 3: ISO-NE Historical Day-Ahead Energy Prices for the New Hampshire Zone in $/MWh



(Source: ISO-NE)

A key indicator of generating unit performance is capacity factor, which is the amount of energy produced during a specific time period (typically a year or a month) as a percentage of the maximum possible output by the unit for that same period. Ultimately, capacity factor is a good indicator of competitiveness and the ability to produce energy revenues, and is a key component of asset value. Figure 4 shows the trends in capacity factors of PSNH's fossil and biomass units from 2008 – 2012.

Figure 4: Capacity Factors of PSNH Fossil and Biomass Plants 2008-2012



(Source: SNL Data Services)

Two of the key drivers of capacity factor are the energy prices in the market the asset serves, and the fuel cost of the specific generating asset. As shown above, the coal units at Merrimack Station and Schiller Station have experienced a sharp downward trend in operation over the last few years, while the biomass unit (Schiller Unit 5) has been steady and actually increasing. Newington Station's minimal operation, however, reflect the unit's relative indifference to changes in fuel and energy markets. In short, asset values generally follow the combination of power market prices and fuel prices. In simple terms, the higher the market prices relative to the fuel costs, the better for a given asset. In the case of PSNH coal plants, the situation has been the opposite, given the drop in electric wholesale energy prices in ISO-NE. We will explore this phenomenon further in the Asset Value section.

ISO-NE Electricity Price Forecast

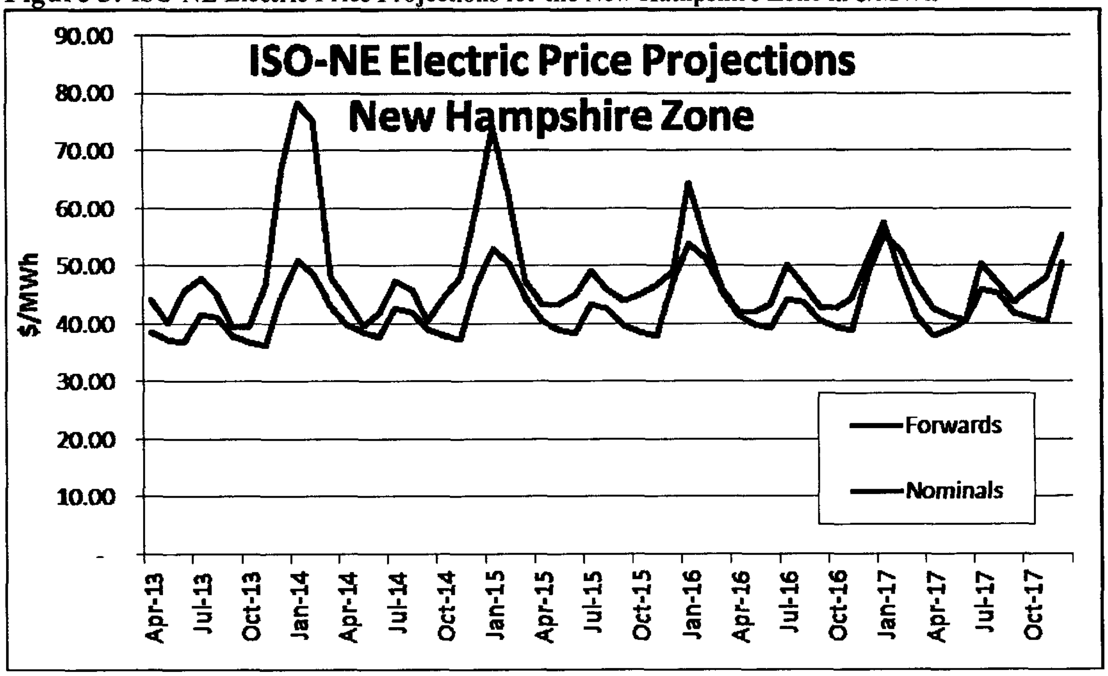
Key to the assessment of a generating unit is the price of energy in the market it serves. Figure 4 displays projections of wholesale electric prices for the New Hampshire zone of ISO-NE.[12] Figure 5 shows forward prices for energy in $/MWh, plotted against a "power nominal" curve.[13] This curve represents a projection of wholesale energy prices based on forward gas prices (at Henry Hub) and historical spark spreads. The result is a long-term outlook of energy prices based on established, highly-liquid forwards for gas at Henry Hub.

It is worth noting the disparity between forward energy prices and the Power Nominals shown in Figure 5. In the first three years of the projections, forward prices are substantially higher than those of the Power Nominals. This result is explained by the fact that Power Nominals do not reflect the very high transportation component of natural gas delivered to New England generators, because they are based on the historical relationship between power prices and Henry Hub gas. Power Nominals therefore do not capture the short-term price spikes to be expected for the next three years in New England winter and summer months. The projections converge after this period, which indicates that traders do not foresee a long-term energy price premium for New England gas transportation issues.

[12] CME Group NYMEX futures, March 2013.

[13] Power Nominals is a third party forecast service provided by RisQuant.

Figure 5: **ISO-NE Electric Price Projections for the New Hampshire Zone in \$/MWh**



(Sources: Forward Prices from CME Group and Power Nominals from RisQuant Energy)

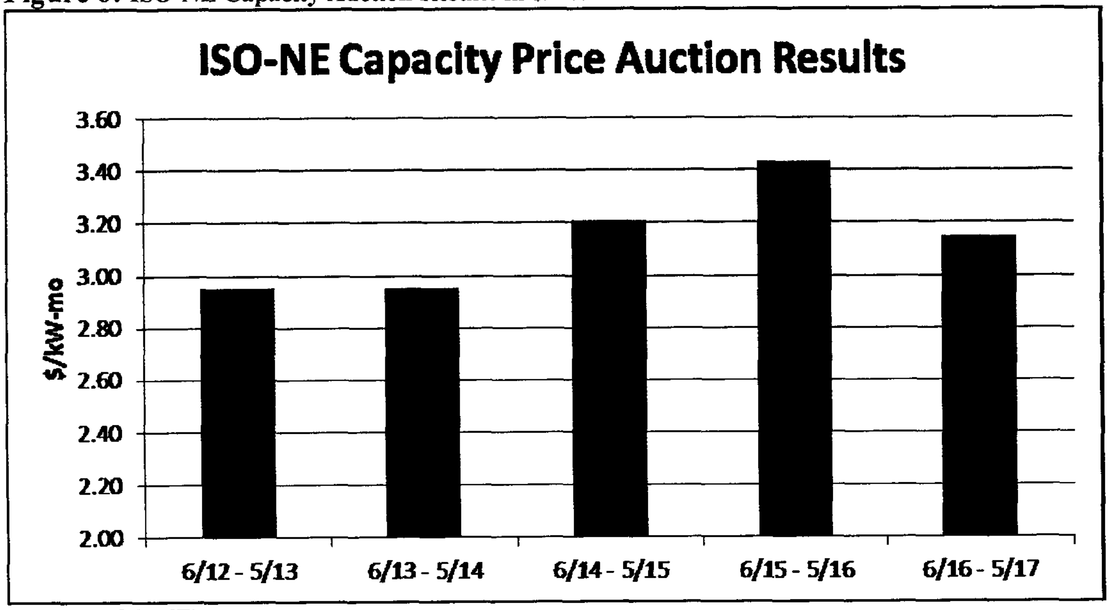
The energy price projections are consistent with the market's expectations that New England gas prices will no longer experience massive transportation-related price spikes after 2016. After that period, the long-term energy prices become flat.

Flat energy prices and low gas prices are not favorable for coal plants like Merrimack and Schiller, which are considered to be a hedge against the volatility of natural gas. The continuation of low gas prices and the corresponding low energy prices will continue to keep the PSNH coal units from generating at a high capacity factor. Further, they are a key driver in the asset value ranges calculated in the Asset Values section.

ISO-NE Capacity Prices

Electricity supply sources are also eligible to receive capacity market revenues through the Forward Capacity Market. The Forward Capacity Market (FCM), operated by ISO-NE, is the mechanism in which ISO-NE procures enough resources to meet its forecasted demand. The FCM is also intended to provide compensation for the capacity cost of existing generation, imports, and demand resources, and to attract new resources into the market. Forward capacity prices are derived by ISO-NE auctions, and the results of those auctions are displayed in Figure 6. Prices throughout the period of our assessment fall in the range of \$3.00-3.50 per kW-month, or \$36-\$42/kW-yr.

Figure 6: ISO-NE Capacity Auction Results in $/kW-mo



(Source: ISO-NE)

After May 2017 the capacity prices are unknown and may actually be lower due to the removal of a floor price from the auction structure. Low-capacity factor units such as Newington and PSNH's combustion turbines derive their primary value from revenues received in the capacity market which, therefore, enhances asset value. This is particularly the case if the revenues generated from the capacity market are not offset by high fixed O&M costs, which is the case for PSNH peaking units, as discussed in more detail in the asset value section.

The New England Natural Gas Market

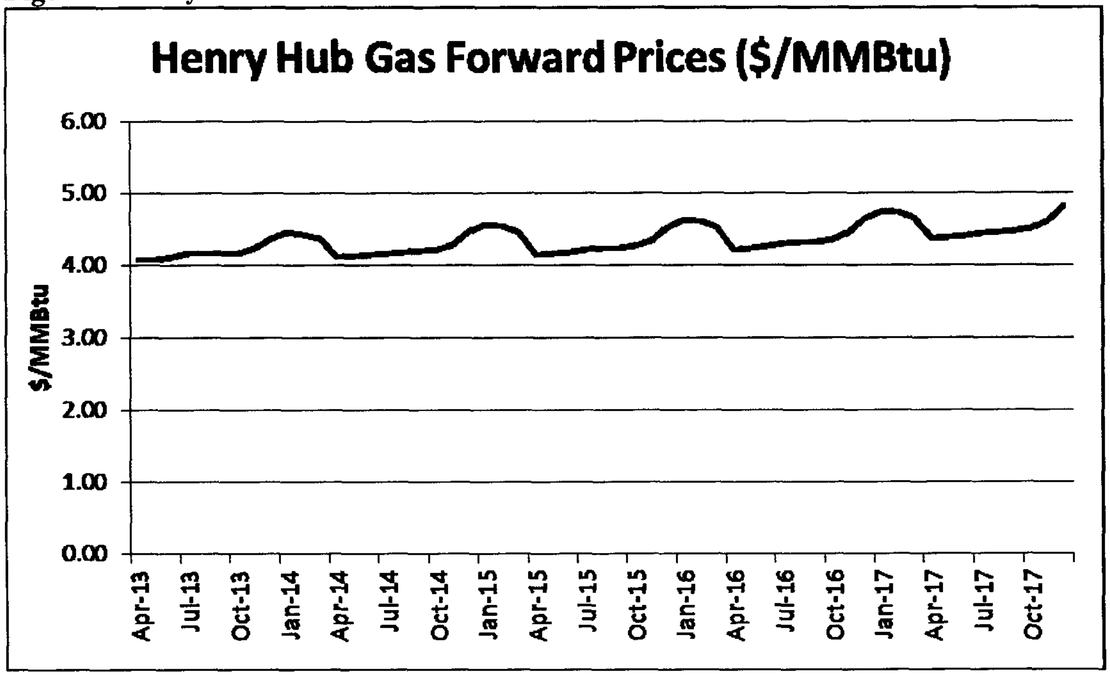
The U.S. Department of Energy, Energy Information Administration's 2013 Reference Case forecast shows Henry Hub prices about constant through 2015, then experiencing a significant increase (plus 16%) in 2016, followed by steady 4 to 7% (nominal) increases through 2025.

The futures market shows annual average basis differential between Henry Hub and the Algonquin City Gates (Boston), declining, from 99 cents per MMBtu in 2013 to 47 cents per MMBtu in 2015.

We see no current reason for the basis differential to increase after 2015. Therefore the outlook is for annual average natural gas prices in New England to decline from about $4.35 MMBtu this year, to about $3.80 MMBtu in 2015. After 2015, a bit of a jump is expected -- to $4.33 MMBtu in 2016, then up by 4 to 7% per year to 2025.

For reference, Figure 7 displays the forward prices for Henry Hub gas from 2013-2017. As expected, the prices, while seasonal, are relatively flat and remain low relative to historical prices.

Figure 7: Henry Hub Natural Gas Forward Prices in $/MMBtu



(Source: CME Group)

PSNH Coal Price Outlook

Merrimack Station

Merrimack Station's cyclone fired boilers use a low ash fusion coal that is typically not forecast by entities such as EIA and SNL.[14] Accordingly, coal prices for this plant are difficult to predict. PSNH coal prices for 2013 are based on existing contract prices. Prices for 2014 and 2015 are based on a combination of contract prices and ICAP[15] forecasts, provided by PSNH, and prices for 2016 are based on a current ICAP forecast.

A subset of Merrimack's fuel prices for 2013 and 2014 includes only existing coal contract prices. These prices are higher than market prices in both years for similar coal, based on data from the Energy Information Administration. Because the overall PSNH price estimates for these years are favorable, we are assuming that PSNH is planning to supplement existing, high priced contracts for these two years, with market prices that are currently low.

In summary, the PSNH coal prices for the years 2013 through 2016 are consistent with estimates of market prices from various sources. These prices do not provide any strategic or operational advantage to PSNH's units, but this information helps to frame the overall discussion of Merrimack's competitive position against low gas prices.

It is worth noting that PSNH has recently installed at Merrimack Station a wet flue gas desulfurization (FGD) scrubber for SO_2 removal. Accordingly, PSNH was asked about the ability to use different, high-sulfur fuels at Merrimack given the SO_2 control technology.

[14] SNL Financial is a provider of industry data and analysis.
[15] ICAP Energy is a broker of fuels and other commodities.

PSNH's response was that it does not see a future with significantly different fuel types used, given the parameters required of a cyclone-fired boiler. Further, PSNH asserted that it could take over a year or more to perform testing and implementation of any new fuel or blend for Merrimack.

Schiller Station

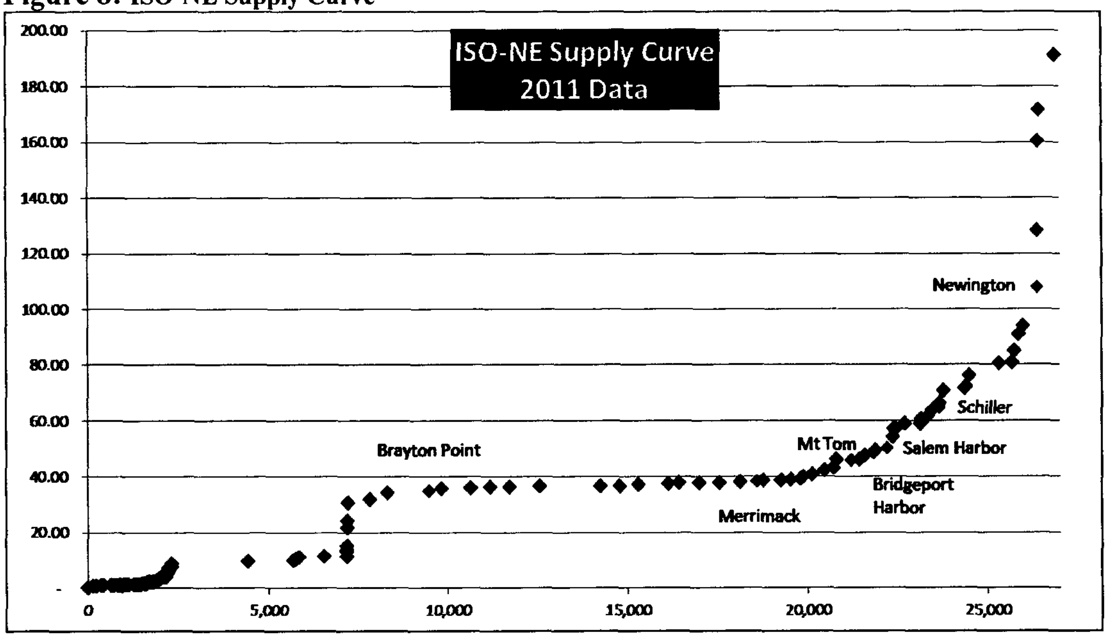
There are no active coal contracts for Schiller Station, other than 560,000 tons of coal remaining to be delivered under a 2008-2011 contract due to supply difficulties encountered at the source mine. The only future forecast coal deliveries to Schiller are for 34,000 tons of coal in 2013.

However, PSNH's forecast of coal prices for Schiller is consistent with market forecasts through 2016. Future fuel prices are based on a philosophy of fuel flexibility to burn either oil or coal at units #4 and #6 (each 50MW) depending on market changes in fuel costs.

PSNH Asset Competitive Position

Based on regional fuel prices and individual unit heat rates (Btu/kWh), a supply curve[16] was developed and is displayed in Figure 8. The supply curve calculates an estimate of dispatch cost (including fuel and variable O&M) provided by SNL for all power plants operating in ISO-NE. While ISO-NE is broken down into zones for pricing purposes, the supply curve is for the entire ISO-NE region.

Figure 8: ISO-NE Supply Curve



(Source: Based on 2011 SNL Data)

On the supply curve, each generating asset within ISO-NE is symbolized by a diamond, which plots the plant on the y-axis by dispatch cost ($/MWh). Each unit is "stacked" from lowest to highest cost (left to right). Based on cost, the plants at the left end of the curve would be expected to be dispatched before the plants to the right of them on the curve. PSNH's

[16] Developed from SNL data for the 2011 time period.

Merrimack, Schiller and Newington plants are displayed as red diamonds, and non-PSNH coal plants are displayed as yellow diamonds.

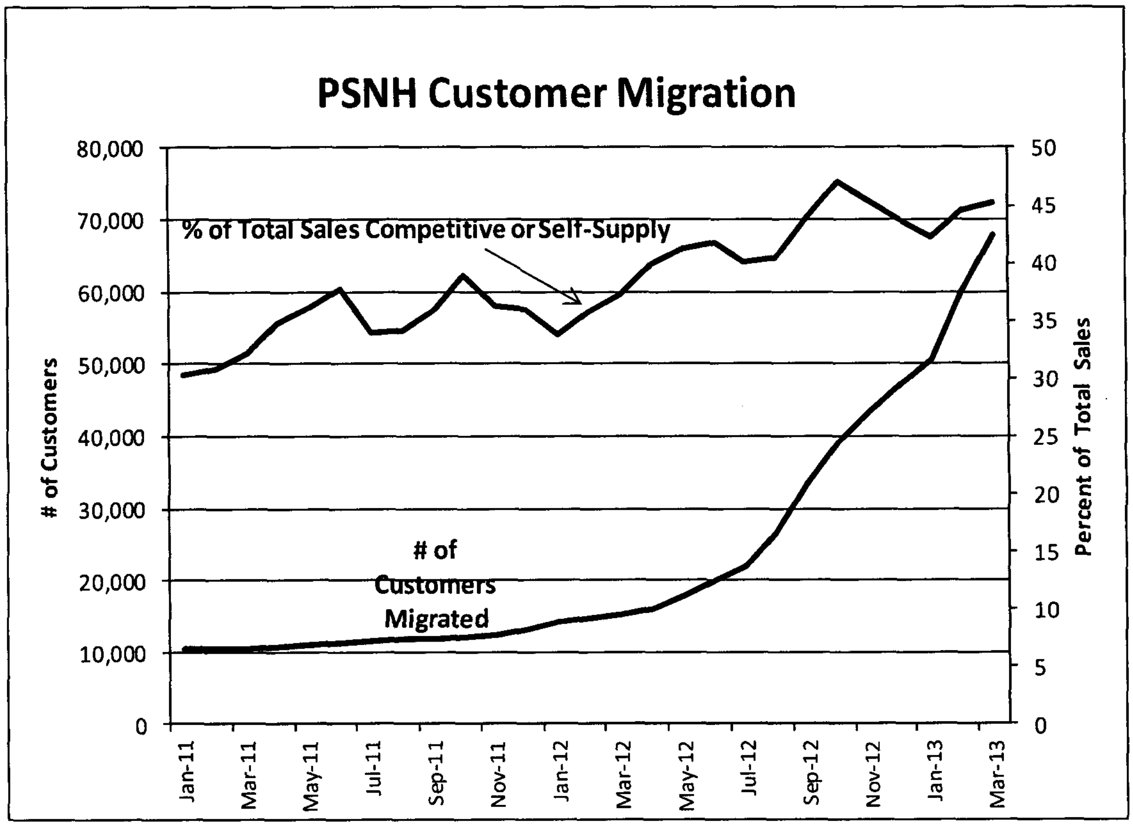
This supply curve highlights that, from a competitive standpoint, Merrimack is substantially behind Brayton Point in the dispatch order, and that Schiller and Newington are even further behind. This circumstance is noteworthy. Brayton Point (shown as the most economic coal plant in ISO-NE by this supply curve) recently sold for just $35 per kW.

Current Conditions and Rate Impacts of Various Factors

Status of Retail Electric Competition in New Hampshire

Retail electric competition in PSNH's service territory today differs starkly from the situation a few short years ago, especially for the residential and small commercial customers. It is important to understand how the situation has evolved. Figure 9 depicts customer migration to competitive supply options in PSNH's service territory since the beginning of 2011:[17]

Figure 9: **PSNH Customer Migration January 2011 – March 2013**

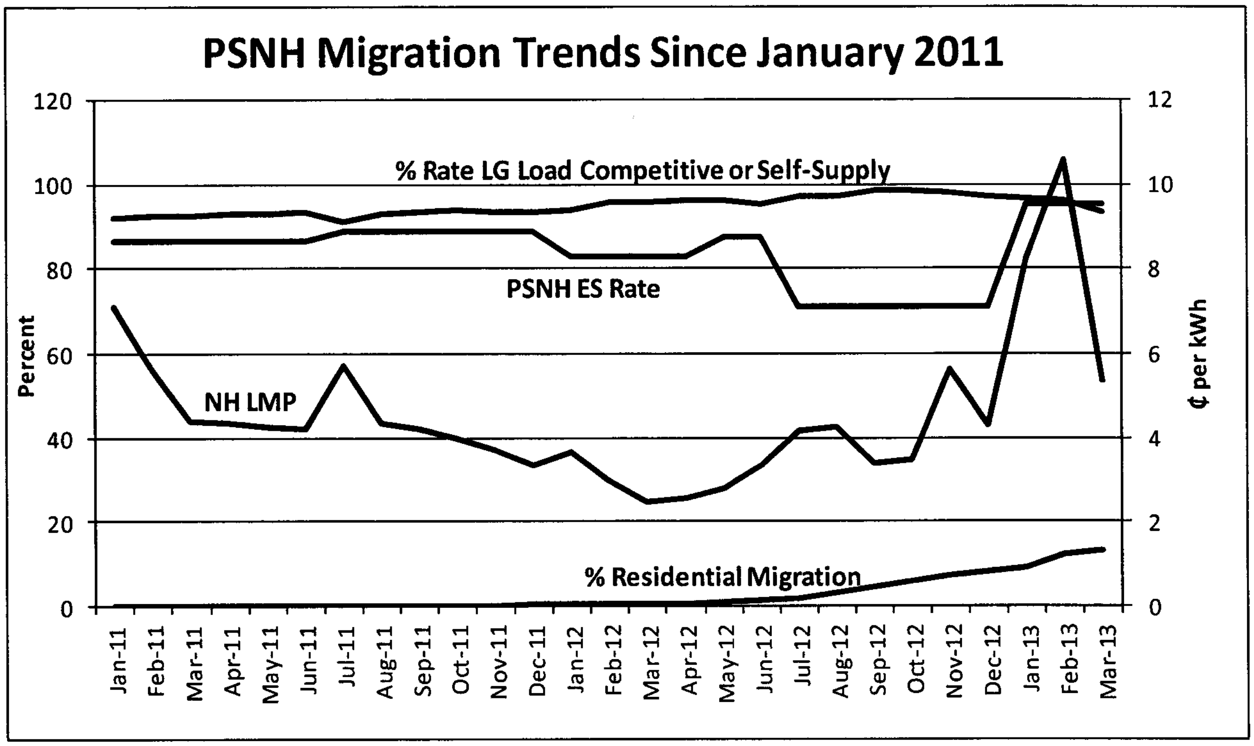


(Source: PUC)

[17] The period beginning with January 2011 was used as it captures both before and after residential customer migration began to become significant.

The number of PSNH customers choosing competitive or self-supply[18] options has been steadily increasing. Figure 10 breaks down the data further:

Figure 10: **PSNH Migration and Price Trends January 2011 – March 2013**



(Sources: PUC and ISO-NE)

The preceding shows that migration in PSNH's Rate LG[19] class has remained relatively constant at more than 90 percent of load. Migration in the residential class has been steadily increasing since the second quarter of 2012. Not coincidentally, that is also the time when the largest gap existed between PSNH's energy service rate and New Hampshire locational marginal price (LMP).[20] Excepting the well-documented natural gas price spike in January and February 2013, PSNH's energy service rate has been above the prevailing market prices.

Table 2 shows that changing market dynamics have led to an influx of applications for registration as competitive power suppliers and electricity aggregators (end of year totals):

[18] Self-supply includes self-generation and direct market purchases.

[19] Rate LG applies to PSNH's largest commercial and industrial customers.

[20] The LMP represents a wholesale price rather than a retail price paid by residential customers. The LMP, however, is a major factor in the retail prices offered by competitive suppliers and is used for purposes of the chart to demonstrate the relationship of PSNH's energy service rate to then-existing market prices.

Table 2

	Competitive Suppliers	Aggregators
2010	8	44
2011	12	57
2012	15	86
2013 (to date)	18	92

Competitive suppliers until recently have served only non-residential customers. PSNH's formerly below-market default service rate made its residential market unattractive to competitors. PSNH's default service rate is now above-market, providing opportunities for competitive suppliers.

Migration of residential customers in the territories of the other New Hampshire electric utilities has been nominal. Current residential migration statistics in those territories have been consistently extremely low (less than 1 percent). A major difference lies in how default service is procured and priced for those other utilities. Those distribution utilities obtain competitive bids to supply their respective default service loads. The resulting retail rates therefore more closely follow the trends in market prices. Opportunities for retail competitive suppliers to attract residential customers away from default service in those territories are limited. If PSNH were to no longer own its generation fleet, and PSNH were then to procure its default service requirements as do the other New Hampshire distribution utilities, it may be that existing opportunities for competitive suppliers in PSNH's service territory would diminish, given that PSNH's default service rate would more closely mirror prevailing market prices. Whether such a decrease in competitive opportunities would be short-term or long-term or beneficial for the long-term competitive market environment are issues that depend on one's point of view. The recently vibrant competitive market for residential customers in PSNH's service territory results directly from PSNH's current situation of owning and operating its generation fleet. If PSNH no longer owns generation, what happens to that market?

Given the increased customer migration being experienced by PSNH, it is important to take a look at some of the major cost drivers and their impacts on PSNH's default service rate.

Rate Scenarios Given Various Assumptions

PSNH's older, inefficient generation fleet with high fixed costs causes PSNH's default service rate to be above-market over almost all of a year. Whether that situation is likely to continue for us is the key question. In order to examine that issue, we requested PSNH to run its energy service rate model using various assumptions. Using PSNH's energy service model as the base was important because it is the same model that historically has been used to calculate the energy service rate, including the calculation that resulted in the current 9.54 cents per kWh rate[21] (8.56

[21] On May 2, 2013, PSNH filed a request for an adjustment to its energy service rate, effective July 1, 2013, to 8.98 cents per kWh (8.00 cents per kWh (non-scrubber) + 0.98 cents per kWh (temporary scrubber recovery)). That rate calculation was estimated as of the time of the filing and is scheduled to be updated prior to the June 20, 2013 hearing.

cents per kWh (non-scrubber) + 0.98 cents per kWh (temporary scrubber recovery)). Using the 9.54 cents per kWh rate as the starting point for a base case, adjustments were made to remove transitory issues, i.e., a prior year under-collection of costs and the return on the energy service deferral that were included in the calculation of that rate. These changes reduce the "base case" rate to 9.32 cents per kWh. We requested model runs that address the following range of assumptions:

- Inclusion of the power purchase agreement with Burgess BioPower
- Customer migration at current level[22]
- Customer migration at 50% of total load
- Customer migration at 60% of total load
- Current (partial) Scrubber recovery (temporary rate adder)
- Scrubber at zero cost recovery
- Scrubber at full cost recovery
- Current natural gas prices
- Increase in natural gas costs of 10%
- Increase in natural gas costs of 25%
- Current coal prices
- Decrease in coal costs of 10%

The various factors and assumptions were analyzed both in isolation and in numerous combinations. The purpose of this analysis was not to develop a precise estimate of PSNH's energy service rate going forward, nor was it to predict whether any particular event may or may not happen.[23] Rather, the focus was on the magnitude of the impact of each of the factors on the resulting energy service rate calculation. The rate scenarios involving "no scrubber recovery" and "full scrubber recovery" were used solely to bound the scrubber rate impact at minimum and maximum levels and should not be viewed in any way as indicating predetermined arguments or positions with respect to scrubber cost recovery. The rate calculations were performed only for a single year, using 2013 as the base year. Attempts to forecast the energy service rate for future years becomes very complicated as numerous changing assumptions would be involved. The factors and assumptions were selected based on changes from the conditions that existed at the time the calculations underlying the 2013 energy service rate were performed. Given constantly changing market conditions, changes in some of the factors may now appear more or less likely.

The calculations are more useful in assessing near-term impacts rather than long-term impacts or rate trends. However, the fuel and energy price forecasts discussed elsewhere in this report provide an indication of the directions factors such as fuel prices and customer migration may be headed. Many other alternate scenarios and changing factors can be posited, but it is important to keep in mind that the focus should be on where rates may be headed based on a range of

[22] "Current level" refers to the 42.5% migration level as of the end of October 2012 that was used to calculate the current 2013 energy service rate. On May 30, 2013, PSNH submitted a response to a discovery request in DE 12-292 that showed the migration rate had increased to 49.9% of total load as of the end of April 2013.

[23] For example, while there are differing views on whether a cooling tower may ultimately be required to be installed at Merrimack Station and, if so, when that would occur and how much it would cost, if a cooling tower were required it would increase PSNH's default service rates above the level that would otherwise be in place at that time.

potential outcomes. Table 3 presents, in summary form, the results of the various rate scenarios, compared to the base case scenario of 9.32 cents per kWh:

Table 3

Case #	Scenario	Migration Rate	Scrubber Recovery	Gas Prices	Coal Prices	Berlin @ PUC PPA levels (a)	ES Rate ¢/kWh	Difference from Base Case ¢/kWh
1	Base w/ Berlin PPA	Current	Yes-current	Current	Current	Yes	9.33	0.01
2	High Migration Case 1	50%	Yes-full	Current	Current	Yes	10.17	0.85
3	High Migration Case 2	60%	Yes-full	Current	Current	Yes	11.06	1.74
4	Scrubber	Current	No	Current	Current	Yes	8.35	(0.97)
5	High Gas Case1	Current	Yes-full	+10%	Current	Yes	9.92	0.60
6	High Gas Case 2	Current	Yes-full	+25%	Current	Yes	10.15	0.83
7	Low Coal	Current	Yes-full	Current	-10%	Yes	9.59	0.27
8	Combinations	50%	Yes-full	+10%	-10%	Yes	10.15	0.83
9		50%	Yes-full	+25%	-10%	Yes	10.20	0.88
10		50%	No	+10%	-10%	Yes	8.59	(0.73)
11		50%	No	+25%	-10%	Yes	8.64	(0.68)
12		60%	Yes-full	+10%	-10%	Yes	10.90	1.58
13		60%	Yes-full	+25%	-10%	Yes	10.78	1.46
14		60%	No	+10%	-10%	Yes	8.95	(.37)
15		60%	No	+25%	-10%	Yes	8.83	(.49)

(a) "Berlin @ PUC PPA Levels" means the Burgess BioPower PPA at the cost rates and purchase levels included in Order No. 25,213 (April 18, 2011) in Docket DE 10-195.

Case #1 through Case #7 involved isolated changes as compared to the 9.32 cents per kWh base case. Case #8 through Case #15 postulate various combinations of the changing factors. We recognize that certain combinations of changing factors, by their nature, would be more likely to occur simultaneously than other combinations. The above scenarios, however, represent a reasonable range of potential outcomes for the purpose of trying to gauge the direction of PSNH's default service rate.

We observed the following about the drivers of change in PSNH's default service rates:

- All scenarios result in a default service rate above the rates currently offered by competitive suppliers.
- The Burgess BioPower PPA should have minimal impact on the energy service rate, especially during the first two years, due to the significant pricing discount (50 percent) for the Class I renewable energy certificates.
- The scenarios showing a decrease from the base case all involve "no scrubber recovery" as the current temporary rate adder would be removed from the default service rate.

The results of the scenarios bear on the question of whether there is a point at which the default service rates would be considered no longer just and reasonable even though they are cost-based rates. If so, identifying what point and how it would be determined becomes critical. Default service was originally intended as a form of backstop or provider-of-last-resort service. Thus, one can also ask whether it matters if the rate has a significant variance from prevailing market prices.

Impact of Scrubber Recovery

Currently, PSNH has been allowed to begin recovery of a portion of its Scrubber costs, on a temporary basis, at the rate of 0.98 cents per kWh.[24] That rate is added to the non-Scrubber default service rate and is charged only to those customers who take PSNH's standard default service. As the rate adder was implemented on a temporary basis, pursuant to RSA 378:27, any difference (higher or lower) between the final determination of the level of permanent rate recovery versus the level of temporary rate recovery will ultimately be reconciled through default service rates.[25] There is currently a proceeding before the Commission to review PSNH's costs of complying with RSA 125-O:11, et seq, Docket DE 11-250. While it is currently unknown when the proceeding will be completed and what the final resolution will be, any discussion of the rate impacts of the Scrubber can be bounded by using scenarios where a) there is zero cost recovery, and b) where there is 100% cost recovery. As noted above, those two cost options were included in the various rate scenarios PSNH was requested to run.

To develop an estimate of the impact of full Scrubber cost recovery, the starting point is PSNH's estimate of the annual revenue requirement associated with the Scrubber. In the temporary rates portion of DE 11-250, PSNH testified that the annual Scrubber revenue requirement was $55.5 million. The 0.98 cents per kWh temporary adder approved by the Commission in DE 11-250, while involving the use of a 66 percent Temporary Rate Cost Percentage, effectively provides for more than 66 percent recovery of the annual revenue requirements associated with the Scrubber. The derivation of the 0.98 cents per kWh rate had the following components:

- 66 percent of the annual revenue requirements ($55.5 million x 66 percent = 36.6 million)
- Unrecovered Scrubber costs from 2011 = $13.1 million

Those two components totaled $49.7 million which, when divided by the then-estimated annual kilowatt-hour sales, produce a rate increment of 0.98 cents per kWh. PSNH, however, has since experienced increased customer migration, which produces lower annual default service sales. Its May 2, 2013 filing in Docket DE 12-292 (the mid-year review of its energy service rate) estimated its 2013 annual sales at 4,272,414 megawatt-hours. That level of sales supports PSNH collecting approximately $41.9 million in Scrubber cost recovery during 2013. Assuming the temporary rate adder is in effect for the duration of the year, that leaves approximately $13.6 million of 2013 Scrubber costs unrecovered. In addition to that estimated $13.6 million of unrecovered 2013 costs, PSNH has also stated that it had $50.1 million of unrecovered deferred costs associated with the Scrubber as of December 31, 2012. Assessing the impact of the costs of the Scrubber, assuming full cost recovery, the following amounts, therefore, require consideration:

[24] Order No. 25,346 (April 10, 2012).

[25] Pursuant to RSA 125-O:18, "If the owner [of Merrimack Station] is a regulated utility, the owner shall be allowed to recover all prudent costs of complying with the requirements of this subdivision in a manner approved by the public utilities commission. During ownership and operation by the regulated utility, such costs shall be recovered via the utility's default service charge. In the event of divestiture of affected sources by the regulated utility, such divestiture and recovery of costs shall be governed by the provisions of RSA 369:B:3-a."

- Annual unrecovered costs of $13.6 million
- Accumulated unrecovered costs of $50.1 million as of December 31, 2012

The currently estimated level of 2013 sales would require the temporary rate adder of 0.98 cents per kWh to increase to approximately 1.30 cents per kWh in order to recover fully the $55.5 million annual revenue requirements. In addition, 1) the $50.1 million of unrecovered Scrubber costs as of December 31, 2012, plus 2) any additional unrecovered costs that accrue between December 31, 2012 and 3) the implementation of any Scrubber-related rate increase, would need to be factored into rates, possibly by means of a multi-year amortization of the costs.

For example, assume a scrubber-related rate increase effective January 1, 2014, a three-year amortization of previously unrecovered costs and energy service sales at the current 2013 estimated level. The estimated unrecovered costs at that time would be $63.7 million ($50.1 million + $13.6 million). A three-year amortization would result in $21.2 million to be recovered annually. The overall Scrubber rate impact would then be approximately 1.80 cents per kilowatt-hour (an increase of 0.82 cents per kilowatt-hour above the current 0.98 cents per kWh temporary rate adder).

Rate Impact of PPA with Burgess BioPower

Another item specifically identified in the order of notice as a factor to be considered is the expected impact on default service rates resulting from the power purchase agreement PSNH entered into with the currently under construction Burgess BioPower biomass generating facility.[26] Case #1 listed in the previous table changed the base case only by including the Burgess BioPower contract for a full year. The far right column shows the rate impact at only 0.01 cents per kWh. This marginal increase is due in large part to the pricing structure established by the Commission, particularly the pricing of the Class I Renewable Energy Certificates (RECs)[27] to be purchased under the agreement. During the first two years of the twenty-year agreement, the RECs are priced at 50% of the Class I Alternative Compliance Payment (ACP)[28], followed by five years at 80%, five years at 75%, five years at 70% and the final three years at 50%. The base energy price of $69.80 MWh is above current market energy prices, but that is offset by the below-market cost of the Class I RECs.[29] As a point of reference, the 2013 Class I ACP is $55.00/REC. By purchasing a maximum of 400,000 Class I RECs under the PPA at a 50% discount, PSNH and its customers save up to $11,000,000 per year over the first two years of the contract when compared with PSNH paying the ACP price for the same quantity.[30]

[26] See Docket DE 10-195.
[27] One megawatt-hour of generation from a qualifying renewable facility equals one REC.
[28] Pursuant to RSA 362-F:10, II, to the extent an electricity provider does not acquire sufficient RECs to meet the annual requirements of a particular REC Class, it may meet those requirements by making payments into the Renewable Energy Fund at rates established by that statute and subsequently updated by the Commission.
[29] There are many other factors involved in the pricing of the Burgess BioPower PPA that will impact any detailed analysis of the PPA's impact on rates in future years, including limitations on the annual energy output and RECs purchased by PSNH, capacity pricing, etc., but the energy and REC pricing have the largest impact on rates.
[30] If PSNH were to purchase Class I RECs from other sources rather than pay the ACP, the cost differential would be lower, assuming that RECs could be acquired at prices below the ACP.

Environmental Issues

In addition to the current inability of PSNH's coal units to compete long-term based on fuel prices and energy price projections, environmental issues are—and will continue to be—a major source of risk for PSNH fossil plants and will have varying upward cost impacts—and, therefore, rate impacts—in terms of capital and O&M spending. This is true of the fossil-fired units only. At this time, PSNH's hydro fleet is free from any substantial, looming environmental issues. This report is not focused on whether or when such requirements may come into play. Rather the focus is to point out the existing and potential concerns and risks that are vital considerations in determining what paths to explore going forward. Below is a brief discussion of the major environmental issues on the horizon.

Water Issues

Merrimack Cooling Tower

In particular, the Merrimack plant is facing a potential major capital expense to construct a cooling tower required by the EPA to deal with reduced thermal discharge and reduced withdrawals of water from the Merrimack River.[31] This is in addition to the existing economic challenges at Merrimack. If ultimately required, the cooling tower is currently estimated to be a $111.3 million capital investment, according to the EPA. This is equivalent to a levelized cost of $10.3 million per year.[32] The draft NPDES permit also includes requirements concerning an improved fish return system (to return fish that have been impinged in the intake system safely to the river) and controls on the discharge of pollutants from the scrubber wastewater. Currently, the EPA is in the process of drafting responses to the voluminous comments received in response to the draft NPDES permit and, according to NHDES, the EPA intends to issue a final permit later in 2013.

If the requirements in the draft permit remain in the final permit, it is expected that PSNH will most likely appeal as it has stated it does not agree with the findings made by the EPA. The appeal process and, depending on the results of an appeal, construction of a cooling tower could take several years. In light of the existing market pressures for Merrimack, the cooling tower requirement poses an additional and significant risk to the economic viability of Merrimack.

Air Issues

Mercury Air Toxics

Air toxics issues represent another key challenge for PSNH coal-fired generation. Mercury Air Toxics (MATS) requirements currently have an April 16, 2015 compliance date, although there is the opportunity for a one-year extension. Merrimack will likely comply with the emissions requirements of the MATS due to the construction and operation of the new FGD scrubber. However, compliance stack testing/monitoring done in accordance with the federal requirements is necessary to determine compliance. Merrimack may also be subject to additional monitoring

[31] September 27, 2011 United States Environmental Protection Agency (EPA), New England – Region 1, "Draft National Pollutant Discharge Elimination System Permit to Discharge to Waters of the United States Pursuant to the Clean Water Act" (NPDES Permit), available at: http://www.epa.gov/region1/npdes/merrimackstation/index.html.

[32] Both the $111.3 million capital investment and the $10.3 million levelized cost are in inflation adjusted 2010 dollars.

requirements including the installation of a new mercury monitoring system. Schiller has undergone some testing and it is uncertain at the present time what, if any, controls, operational limitations, or additional monitoring requirements will be necessary for MATS compliance.

SO_2

The new one-hour standard established by the EPA in 2010 requires states to demonstrate attainment with the new National Ambient Air Quality Standard for SO_2. As part of this demonstration, Merrimack, Schiller and Newington Stations may be required to implement additional control measures, operational restrictions and/or monitoring requirements in order for the state to reach and/or maintain attainment of the new standard. The operation of the Scrubber at Merrimack demonstrates compliance with the new standard however, additional control measures and/or restrictions may be necessary to address operation of Unit 1 in bypass mode (emissions from Unit 1 bypassing the scrubber and discharging through the old Unit 2 stack). Due to the delay in federal implementation guidance, the impacts on Schiller and Newington are uncertain at this time. Once federal guidance and/or federal regulations are complete for the implementation of this new standard, a full evaluation of compliance will be finalized in accordance with the federal requirements. Schiller and Newington may be subject to additional control measures, operational restrictions and/or monitoring requirements.

Regional Haze

Pursuant to federal CAA requirements, New Hampshire established its Regional Haze Rule, Env-A 2300[33], on January 8, 2011. The rule was approved into New Hampshire's federally required State Implemntation Plan (SIP) on Aug. 22, 2012 (77 FR 50602). Regional haze requirements have a two-and-a-half year compliance schedule with a compliance date of June 1, 2013. PSNH stated that representatives of Merrimack Station and Newington Station worked with the New Hampshire Department of Environmental Services (NHDES) to determine what controls and work practices (fuel blending, etc) would be required to meet the regional haze goals. PSNH stated that it submitted to NHDES the expected costs to comply with the rule (which were not quantified) and further stated that it anticipates no additional capital costs will be needed to comply with the rule.

RGGI

Costs to comply with the Regional Greenhouse Gas Initiative (RGGI) are included in PSNH's generation costs. PSNH currently receives an annual allocation of 1.5 million CO_2 allowance. These "bonus" allowances will go away after 2014, therefore PSNH will need to purchase the necessary allowances at market price ($3 – $4 per ton estimated range for an estimated annual cost of $4.5 – $6.0 million). PSNH noted that its earned bank of bonus allowances held by NHDES is almost 17 million,[34] and it will discuss with the legislature the opportunity to continue authorization of the granting of allowances pursuant to RSA 125-O:24.[35] Absent continued authorization for the allowances, RGGI compliance will pose an additional cost burden to PSNH's fossil generating units and its default service customers.

[33] See http://des.nh.gov/organization/commissioner/legal/rules/documents/env-a2300.pdf

[34] NHDES estimates that once the 2013 and 2014 allowances are taken into account, the number will be closer to 18 million.

[35] See RSA 125-O:24, VIII and IX: http://www.gencourt.state.nh.us/rsa/html/X/125-O/125-O-24.htm.

Alternatives in Moving Forward

When looking to future years and exploring the issues of PSNH's continued ownership and operation of its generating assets along with the related impacts to the competitive electricity market, the Commission's Mission Statement provides guidance in addressing the issues we face here:

> To ensure that customers of regulated utilities receive safe, adequate and reliable service at just and reasonable rates.
>
> To foster competition where appropriate.
>
> To provide necessary customer protection.
>
> To provide a thorough but efficient regulatory process that is fair, open and innovative.
>
> To perform our responsibilities ethically and professionally in a challenging and supportive work environment.

The circumstances require the Commission to address a number of important subjects, which are in tension with one another in certain respects:

- PSNH's default service rate and its relation to market prices
- A robust competitive electricity market
- The financial health of New Hampshire's largest utility
- Environmental concerns
- Fuel diversity

Different stakeholders have differing views of the priority of those areas of importance.

PSNH has consistently touted the benefits of its generation fleet, particularly from the perspective of fuel diversity and as a hedge against market price spikes. PSNH's generating assets, given their wide variety of fuel sources—coal, gas, wood, water—offer some limited options and hedging ability when one or more fuel sources undergo disruption. PSNH believes that the current natural gas fuel supply and price advantages are not structural. Therefore, PSNH considers it appropriate to retain its generation fleet with its current composition to provide default service to its customers. PSNH provided general New England market information concerning the region's reliance on natural gas and current gas supply constraints, but did not provide any analysis particular to its generation fleet to support a positive future outlook for the plants. PSNH's default service rate has been over-market for the last few years, and it appears that it will remain so for at least the near future. One can therefore question the wisdom of retaining the assets. The next logical step then is to explore alternative approaches with respect to PSNH's generation fleet along with the advantages and disadvantages of each approach. Among the available approaches are the following:

- Status Quo
- PSNH sells all of its plants (including entitlements)
- PSNH sells some of its plants and entitlements
- PSNH retires some plants
- PSNH transfers its plants to a new competitive affiliate

We find pros and cons associated with each of the approaches centering on factors such as timing, complexity, rate implications and the potential need for legislative changes. Sale or retirement of PSNH's generating units are governed by RSA 369-B:3-a:

> **Divestiture of PSNH Generation Assets.** – The sale of PSNH fossil and hydro generation assets shall not take place before April 30, 2006. Notwithstanding RSA 374:30, subsequent to April 30, 2006, PSNH may divest its generation assets if the commission finds that it is in the economic interest of retail customers of PSNH to do so, and provides for the cost recovery of such divestiture. Prior to any divestiture of its generation assets, PSNH may modify or retire such generation assets if the commission finds that it is in the public interest of retail customers of PSNH to do so, and provides for the cost recovery of such modification or retirement.

How parties interpret that statute will also play into the exploration of those alternatives.

Status Quo

By far the simplest approach from both timing and logistical perspectives—and the approach apparently preferred by PSNH— is for PSNH to continue owning and operating the plants as it currently does and use the plants to provide default service pursuant to RSA 369-B:3, IV(b)(1)(A). "Status Quo" is apparently PSNH's answer to "how PSNH proposes to maintain safe and reliable service to its default service customers at just and reasonable rates in light of those market conditions." However, as discussed earlier in this report, the current situation has in recent years resulted in above-market default service rates and an increasing rate of customer migration away from PSNH's default service rate which puts continuing and increasing upward pressure on that rate. PSNH has instituted changes to its plant operations and purchasing strategies in light of changing market conditions. Despite those changes, however, cost pressures have created a situation that appears unsustainable.

Under a status quo approach, PSNH's default service customers get the benefit of any below-market generation costs, incur the detriment of any above-market generation cost. They pay for PSNH's fixed costs associated with the facilities. The risks and rewards to the affected customers of such an approach vary widely depending on volatile fuel and energy market conditions. In the earlier years of restructuring PSNH's default service rate was below market, thereby providing a benefit to PSNH's default service customers. Over the last few years the situation has reversed and those customers who have continued to take default service from PSNH have been paying above-market rates. As shown by the results of the various rate scenarios, the current situation of above-market PSNH default service rates will likely continue even under a range of possible scenarios.

PSNH sells all of its plants (including entitlements)

As of March 31, 2013, PSNH's generating units had the following net book values:

Table 4

PSNH Generating Plant Balances as of March 31, 2013 ($000)				
	Gross Plant	Depreciable Plant	Accumulated Depreciation	Net Plant
Generating Unit				
Fuel-fired				
Merrimack Station	662,858	662,758	159,029	503,829
Newington Station	150,204	147,787	112,813	37,391
Schiller Station	214,166	213,704	130,429	83,737
Wyman No. 4	6,961	6,943	6,271	690
Combustion Turbines	10,937	10,925	10,078	859
	1,045,126	1,042,117	418,620	626,506
Hydroelectric				
Amoskeag	12,778	12,410	3,814	8,964
Ayers Island	11,997	11,650	2,296	9,701
Eastman Falls	9,368	9,098	3,711	5,657
Garvins Falls	11,717	11,638	4,862	6,855
Smith	9,283	8,870	2,915	6,368
Other Units	13,392	13,021	3,721	9,671
	68,535	66,687	21,319	47,216
Totals	1,113,661	1,108,804	439,939	673,722

For purposes of a sale, the sales proceeds would ideally cover the net book value remaining as of the time of the sale. The table above shows the total net book value of PSNH's generation fleet as of March 31, 2013 to be approximately $674 million.[36] In order for there to be no "loss" (a/k/a stranded costs) from a sale, the plants would collectively have to net at least $674 million through a sale.

PSNH also has in place the following power purchase agreements (PPAs):

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[36] The totals include the full cost of the Scrubber as reported on PSNH's books. The inclusion of the Scrubber for purposes of this analysis serves solely to frame the discussion. Issues related to the prudence and cost recovery of the Scrubber will be determined by the Commission in DE 11-250.

- 15-year PPA with 24 MW wind facility in Lempster, New Hampshire
- 20-year PPA with 75 MW Burgess BioPower biomass facility in Berlin, New Hampshire

PSNH began purchasing power and RECs under the Lempster PPA in October 2008. The Burgess BioPower facility is expected to commence operations in November 2013.[37] Given the relatively small impact the PPAs have on PSNH's default service rate, we did not attempt to estimate the values of the PPAs. Their pricing terms involve a number of combined assumptions—as well as potential purchasers' views on those assumptions—including expectations of future energy and capacity market prices, Class I REC prices, wood fuel prices, etc.

Taking the $674 million net book value of the generating plants as a reference point, we turn to a calculation of estimated market values for the generating plants given current market conditions.

PSNH Asset Values

One objective of this Staff report is to provide a preliminary, indicative estimate of the market value of PSNH's generating assets. It is important to consider the following caveats to this material:

- The estimates are high level and make many simplifying assumptions, and are therefore not suitable replacement for investment or asset disposition decisions
- The estimate of the value of the hydroelectric assets was based on the review of a transaction involving a comparable set of assets, not the cash flow projections from the facilities
- The asset value estimates of the fossil-fired plants were based on a simplified discounted cash flow (DCF) approach of only the next five years of asset cash flow. This is not a suitable replacement for a detailed project finance model and market modeling
- The fleet value provided is only a preliminary indication of possible asset value for discussion purposes

Several methods are used for estimating the value of power generation assets. The most appropriate for this initiative are:

- Comparable transactions—Identification and review of recent, relevant transactions to establish a $/kW sale price that can be applied to same-type assets for comparative purposes.

- Discounted cash flow (DCF)—This is the approach used by power plant investors, but relies on production cost model runs, a detailed project finance model, detailed data, and projections. Liberty Consulting used a simplified DCF approach and simplifying assumptions to provide an indicative value of PSNH's power plants.

[37] In a response to a discovery request in DE 12-292, PSNH stated that it confirmed with the developer of the project that the targeted in-service date of the Burgess BioPower facility is November 18, 2013.

In order to derive a rough estimate of the values of PSNH's generating assets, we employed both methods. The values estimated in this report should only be considered indicative—actual values can only be determined by soliciting competitive bids from willing buyers and will vary based on market conditions at the time of a sale, bidders' expectations about future energy and fuel market prices and other bidder-specific interests and concerns.

Simplified DCF Approach

DCF is based on Free Cash Flow (FCF), an important component of which is earnings before interest, taxes, depreciation and amortization (EBITDA). It essentially represents operating income. To calculate FCF, EBITDA is then adjusted for taxes (including the tax implications of depreciation, but not depreciation itself which is a non-cash item), and capital expenditures. The resulting FCF is then discounted at a discount rate to reflect expected return on equity and the cost of debt (and the tax implications of debt financing).

In this simple case, we performed a valuation of 5 years of free cash flow due to the uncertainty of the PSNH assets beyond 5 years. It is worth noting that investors generally use a 10-20 year time frame in asset valuation studies, and that this simple assessment was designed to give a preliminary indication of value only. For each asset, or group of assets, analyzed, a weighted average cost of capital (WACC) was used to discount the cash flow. The WACC was calculated as a function of percent debt, the cost of debt, the return on equity (ROE) and income tax rate. For the purposes of this indicative analysis, the following WACC parameters[38] were used:

Debt Portion	60.00%
Debt Rate	6.75%
ROE	12.75%
WACC	**7.61%**
Tax Rate	38.00%

It is worth noting that power plant values, when based on DCF calculations, are sensitive to a number of operational, market and financing parameters, including the parameters that comprise WACC. Also, the WACC was applied to all the PSNH assets that were analyzed with the DCF approach, although we recognize that investors generally apply higher discount rates to riskier assets (peakers) and lower discount rates to less risky (baseload) assets. Due to these issues, the valuations provided based on the above WACC numbers were tested against a wide range of ROE and debt rate values, and it was shown that this particular analysis is not very sensitive to WACC changes. Since WACC is the cash flow discount rate that is compounded annually, it would play a more important role in the valuation of longer-term cash flow streams.

Merrimack

Merrimack showed significant losses of about $20 million per year of EBITDA. Poor dispatch cost relative to gas prices and very high fixed O&M drove this result. Capital is not a component of EBITDA, but is a component of free cash flow, making the picture for Merrimack even

[38] For the debt portion, debt rate, ROE and tax rate components of WACC were derived from a recent, non-public transaction and are used to develop indicative values of PSNH power plants only.

cloudier. The valuation used capital expenditures projections as provided by PSNH, but these did not account for the possibility of $111 million in capital expenditures for a cooling tower. Fixed O&M represents all operating and maintenance costs that do not vary in relationship to the output of the generating unit. These costs do not impact dispatch cost or capacity factor or the ability for a plant to compete on a marginal cost basis. They do, however, impact plant financials and asset value, and are also recovered by customers in a regulated company such as PSNH.

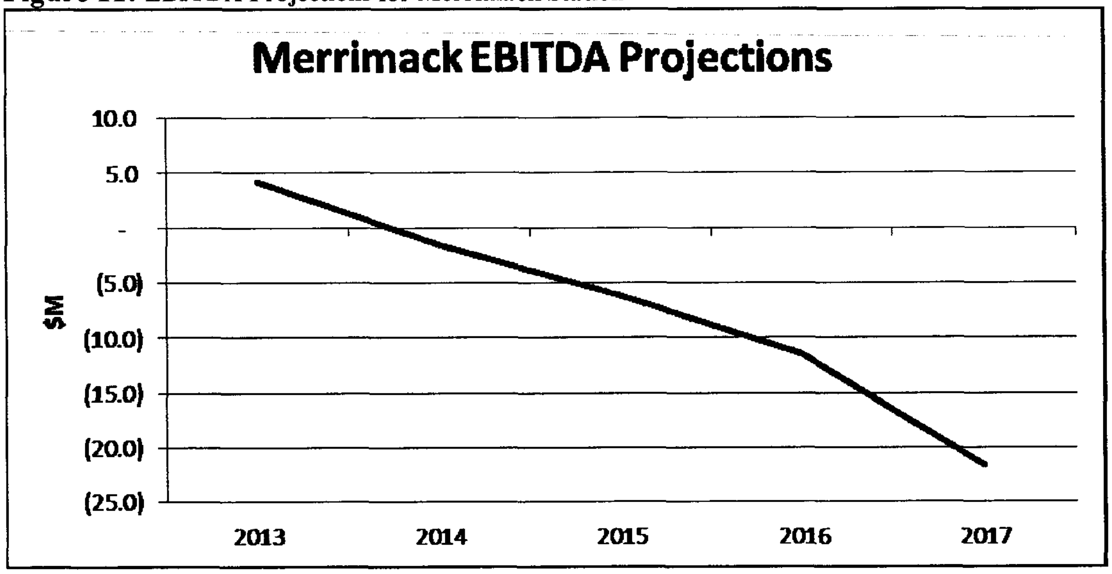
Based on the negative cash flow in each of the five years of this analysis, the value of the cash flow is negative. However, from a market standpoint, the lower limit of value is $0, which is what is estimated for the Merrimack station.

On the other hand, a coal plant in ISO-NE with declining capacity factor, Brayton Point, was recently sold for $35 per kW. For this reason, it is possible that there is also some positive value in Merrimack from sources other than the cashflow contributions from energy and capacity sales. Specifically, there may be value in the actual plant site, and that such value is likely less than or equal to the selling price of Brayton Point, which is a more competitive power plant. As such, we put an upper limit on the potential value of Merrimack at $15.4 million.

DCF valuation = $0/kW (negative value calculated)

Comparable/Site Value = $15.4 million or $35/kW

Figure 11: EBITDA Projections for Merrimack Station



Schiller 4 & 6

Schiller 4 & 6, collectively, show significant losses of about $8-10 million per year of EBITDA. This is driven by poor dispatch cost relative to gas prices and high fixed O&M, and does not include capital costs of $2-3 million per year (capital is not a component of EBITDA, but is a component of free cash flow). The valuation used capital expenditures projections provided by PSNH.

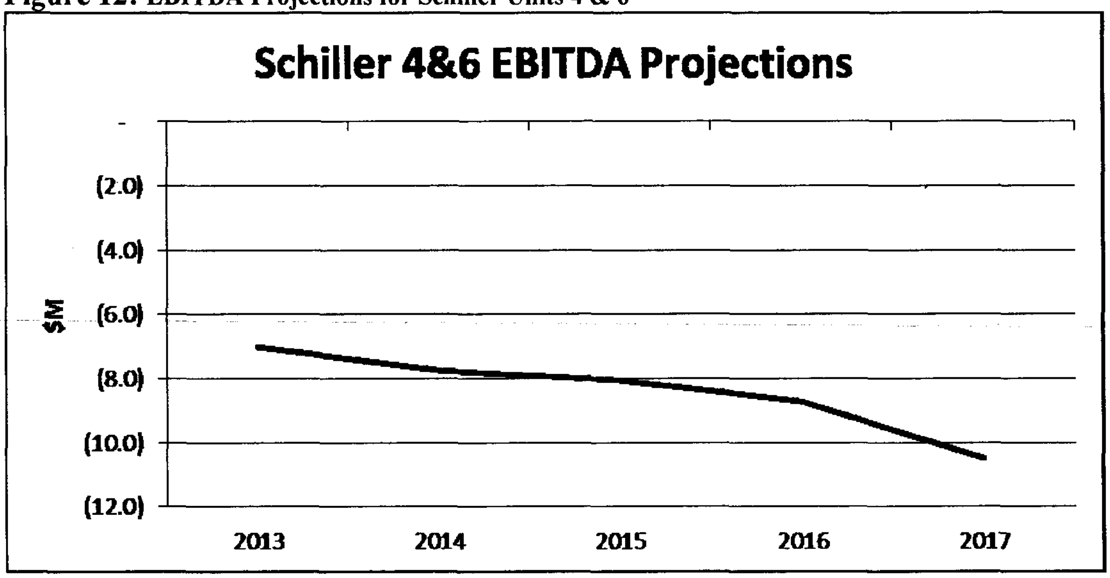
Like their counterpart, Merrimack, the Schiller coal-fired units show significantly negative EBITDA and cash flow, resulting in a DCF valuation of less than $0. Accordingly, our valuation of the cash flow from Schiller's coal-fired units for the 5-year horizon is $0.

But, like at Merrimack, it is possible that there is also some positive value in Schiller 4 and 6 from sources other than the cashflow contributions from energy and capacity sales. Specifically, there may be value in the actual plant site, and that such value is likely less than or equal to the selling price of Brayton Point, which is a more competitive power plant. As such, we put an upper limit on the potential value of Schiller 4 and 6 at $3.4 million.

DCF valuation = $0/kW (negative value calculated)

Comparable/Site Value = $3.4 million or $35/kW

Figure 12: EBITDA Projections for Schiller Units 4 & 6

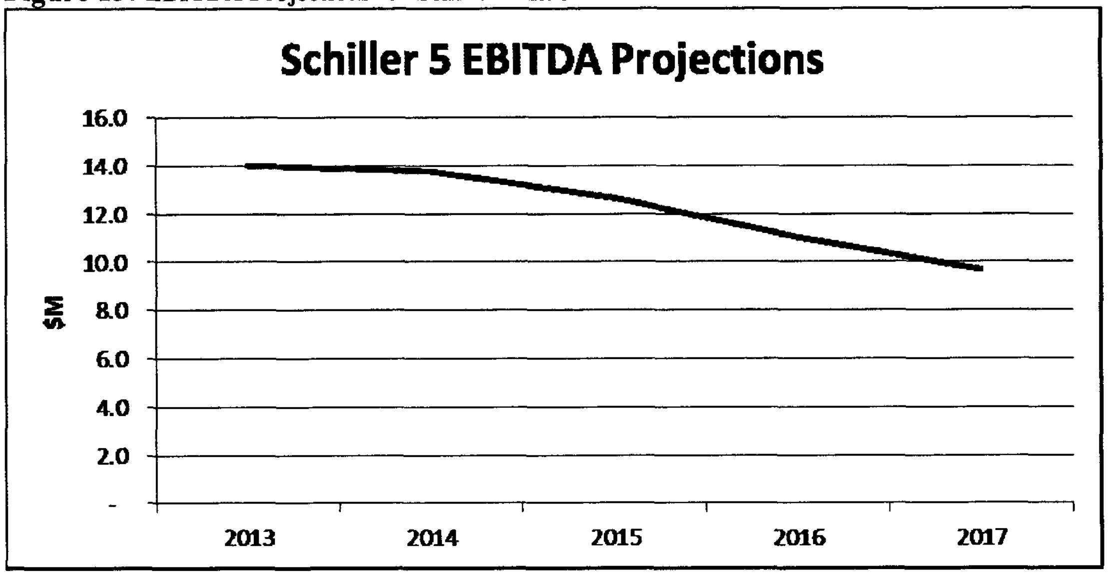


Schiller 5

Schiller 5 shows positive EBITDA from $14 million in 2013 to just under $10 million in 2017. The positive performance is largely due to the high capacity factor and the generation of both RECs and production tax credit (PTC) revenue. These are somewhat offset by high fixed O&M levels. Capital costs are $1-2 million per year (capital is not a component of EBITDA, but is a component of free cash flow), which were provided by PSNH.

DCF valuation = $34.5 million, or $803/kW

Figure 13: **EBITDA Projections for Schiller Unit 5**



Newington

For Newington, capacity factors are expected to remain low or decrease, resulting in very little energy revenue. Moreover, energy revenues at Newington will typically occur when the station is setting the market price, meaning that it will have little or no profit from energy. Accordingly, we assumed $0 net revenue for energy sales from Newington, and assumed it would generate income strictly by providing capacity for simplifying purposes.

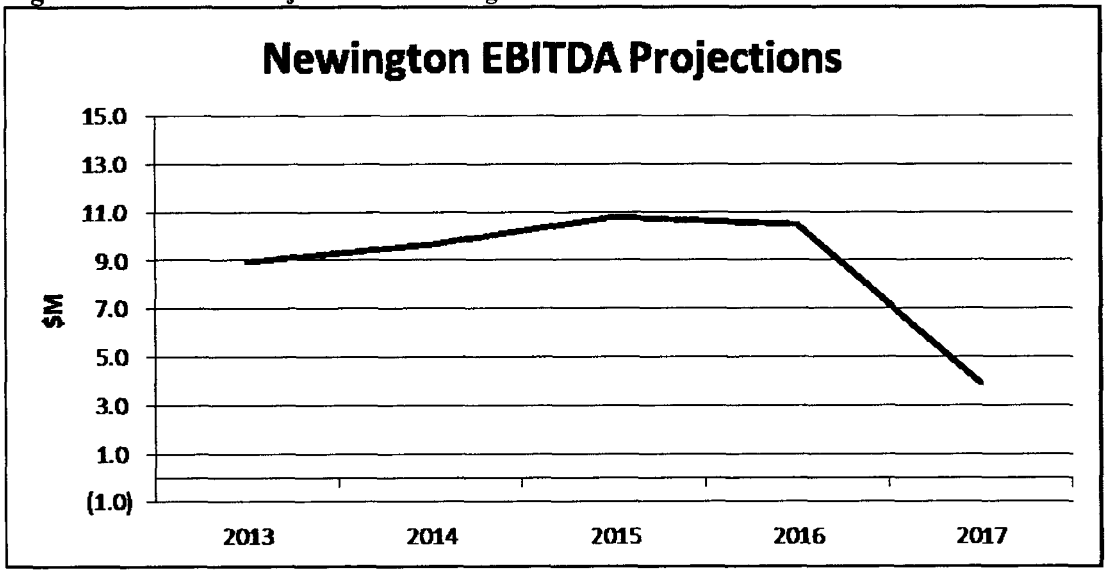
Based on the assumptions, Newington shows positive EBITDA over the next 5 years as a capacity provider, due to low fixed O&M. This results in a valuation of approximately $23 million. It is worth noting, however, that recent events indicate that the outlook for capacity-only units may be bleak.

Specifically, NRG has announced the closure of its Norwalk Harbor Station citing that "It's just too risky to stay in the market as a capacity supplier."[39] This indicates a somewhat comparable asset to Newington was determined as uneconomic by its owner, a point that should be taken into consideration when the PSNH assets are scrutinized in more detail.

DCF valuation = $23 million, or $57/kW

[39] David Gaier, NRG spokesperson, Norwalk Citizen, June 5, 2013.

Figure 14: **EBITDA Projections for Newington Station**



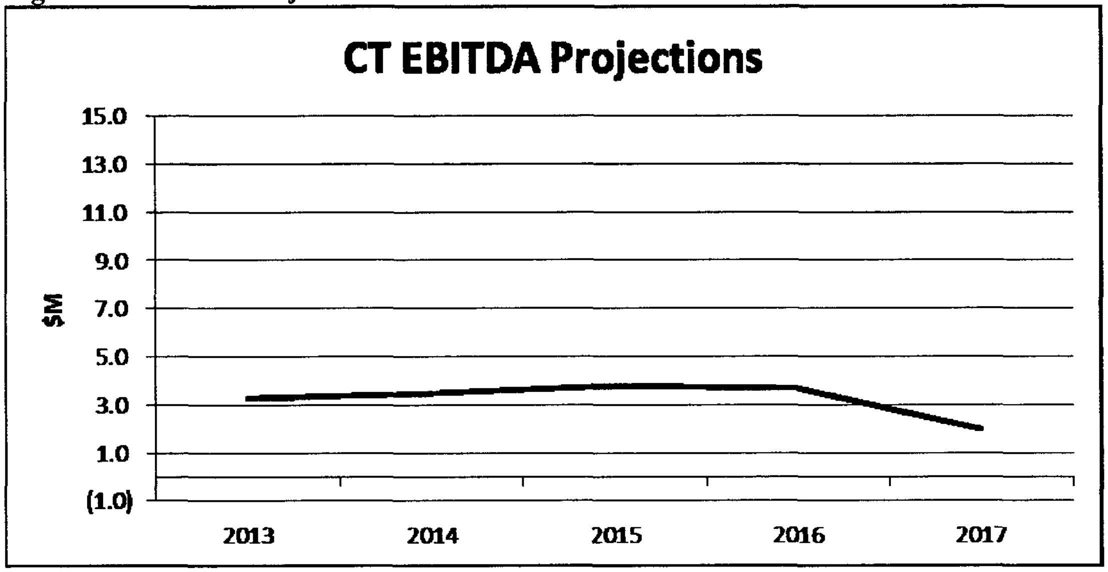
Other Peakers (Combustion Turbines)

Like Newington, which now serves in a peaking capacity, PSNH's simple cycle combustion turbines (CTs) have capacity factors that are expected to remain low, resulting in very little energy revenue. Moreover, energy revenues will typically occur when the units are setting the market price, meaning that they will have little or no profit. Accordingly, we assumed $0 net revenue for energy sales from the CTs, and assumed they would generate income strictly by providing capacity.

Based on the assumptions, the CTs show positive EBITDA over the next 5 years, due to low fixed O&M and high capacity prices, and an assumed $0 for capital additions.

DCF valuation = $9 million, or $90/kW

Figure 15: **EBITDA Projections for PSNH's Combustion Turbine Units**



Hydro Units

Intuitively and empirically, hydroelectric generating assets are at the high end of valuation of all technologies on a $ per kW basis. For this study, recent transactions for hydroelectric plants within ISO-NE have enabled the use of a comparable transactions to predict a value for PSNH hydro units. The PSNH hydro fleet was valued based on this comparable transaction and subsequent discussions with the buyer in that transaction.

In December 2012, Brookfield Power agreed to buy 19 hydro facilities (351 MW) in Maine from Nextera for $760 million, equivalent to $2,165/kW. Our information leads us to believe that the particular characteristics of the PSNH hydroelectric facilities could attract a premium on the order of 10% above those just purchased in Maine.

This assumption would make the PSNH's 70.2 MW of hydro assets worth $2,382 per kW and will be used as a proxy for the value of $167.2 million in this high level analysis.

Comparables valuation = $167.2 million, or $2,382/kW

DCF Valuation Summary

The high-level valuation approach taken in this study would produce for the PSNH generating assets a total market value on the order of $252 million, as displayed in Table 1. Again, these are based on the high-level assessment described above.

Table 5: **Summary of Estimated Asset Values for PSNH Generating Assets**

Type	MW	Basis	Value $/kW	Value $M
Coal	534.6	Cash Flow/Comps	35.00	18.7
Biomass	43.0	Cash Flow	803.41	34.5
Gas Steam	400.2	Cash Flow	56.54	22.6
Hydro	70.2	Comps	2,382.00	167.2
CT	101.5	Cash Flow	89.86	9.1
Total	1,149.5	Combined	219.42	252.2

It is worth noting that the coal unit values are based on a comparable value of $35 per kW from the Brayton Point transaction, despite the fact that the DCF approach showed negative asset value. This was done to reflect value for the site itself, which may ultimately be used to re-power to a gas combined cycle plant utilizing fuel, water and transmission infrastructure and permits.

It is also worth noting that the preliminary indications of Schiller units 4 and 6 having negative DCF value (site value notwithstanding) may offset the positive value of Schiller 5. The ability for Schiller 5 to run as a stand-alone unit was not addressed in this screening analysis.

As shown in the above Figures and Tables, the indicative values of the fleet as a whole fall well short of the net book value to the tune of approximately $420 million ($674 million net book value less $252 million indicative value).[40] On an individual basis, however, there are starkly different results depending on the fuel type and other plant characteristics. This leads to a number of questions:

- If PSNH were to offer its plants for sale, should they be packaged together, individually, or in groups?
- Should PSNH sell only some of its plants? If so, which ones?
- Should PSNH retire some of its plants?

Plant Sale Packaging Options

If a sale of PSNH generating plants were to be pursued, consideration must be given to how the sale is designed. Ideally, a sale should be designed in a way to attract the largest number of potential buyers and produce the greatest overall value. However, different buyers will have different interests based on their individual business plans and other considerations. Some buyers may only prefer one particular plant for whatever reason, but selling the plants on an individual basis could be very time consuming and costly and some plants may go unsold. Therefore, individual sales would not be a recommended course of action.

[40] We recognize that ISO-NE is pursuing options for the upcoming winter period to address the operational problems encountered during this past January and February with natural gas supplies. The proposal may provide additional short-term revenues to some PSNH generating units, however, the program has yet not been filed at FERC and it is not clear whether it would run longer than this upcoming winter period. It is also unclear what effect it would have on the economic value of the PSNH generating plants.

Another alternative would be to sell the plants in groups, e.g., the fossil plants as one group and the hydro plants as another group. Depending on the interests of potential buyers—for instance, if they currently own other fossil or hydro plants—a group sales approach could attract a diverse set of bidders if they find the grouped units to be attractive. The analysis above indicates that, the hydro plants would be expected to draw the highest values on a per kW basis and would likely result in above-book value sale proceeds. The fossil plants, on the other hand, have much lower expected per kW values and could expect to receive below-book value proceeds from a sale. Under a group sale scenario, the combination of the results of sales of the hydro and fossil plants would result in a net determination of whether there still remained net unrecovered book value, commonly referred to as "stranded costs."

The simplest alternative from an administrative perspective would be to package all of the generating plants into one sale. Such an approach would be advantageous if the purpose was to divest all units at the same time. However, bidders who may only be interested in the smaller hydro fleet may not be interested in acquiring the much larger fossil fleet for a number of reasons. If those hydro-focused bidders choose to bid on the entire fleet, their bids could very likely reflect an implicitly lower bid for the hydro units than they would have otherwise been willing to pay. Bidders interested in only the fossil fleet may find it necessary to increase their bids above what they would otherwise pay due to the inclusion of the hydro units.

In summary, in the event of a sale of PSNH's generating units, individual sale of the units would not be recommended. Selling the plants either in groups or as one total package are viable alternatives, but it would be advisable to perhaps seek additional comments or solicitations of interest.

PSNH sells some of its plants

An approach that can be viewed as a version of the group sales approach would be to sell some of the plants. There may be reasons to sell only the fossil units and retain the hydro units due to the hydro units' below-market generation cost. Conversely, some may argue that it would be beneficial to sell only the hydro plants to obtain above-book value proceeds. One drawback to a "sell some of the plants" approach, however, is that PSNH would still be in a hybrid situation, albeit to a much lesser extent. If there is an intent to effectively end the hybrid situation, then selling only some of PSNH's plants would not be a viable alternative.

PSNH retires some plants

Parties have argued in various proceedings that the fossil-fired units of Merrimack, Newington and/or Schiller Stations are prime for retirement due to economic and environmental considerations.[41] In the event of retirement, the net unrecovered book value at that time is still eligible for recovery from customers, but arguments will inevitably arise with respect to such cost recovery—an area that is discussed below. One aspect of retiring a plant, however, is that

[41] Staff notes that in recent years the following fossil-fired plants in New England have either retired, announced retirement or delisted: Salem Harbor (coal), Somerset Station (coal), Thames (coal), Mt. Tom (coal), Norwalk Harbor (oil).

the retained site of the plant may be suitable for redevelopment for a new generating facility or perhaps sold for other potential development. This report does not assess the potential site values of the various generating plants.

PSNH transfers plants to a new competitive affiliate

Given PSNH's repeatedly stated belief in the value of its overall generation portfolio, one option that could be explored is for PSNH to create a new competitive affiliate and transfer its plants to that affiliate. Currently, there is nothing in New Hampshire law that would permit the Commission to compel such an action, so any such transfer would have to be voluntary by PSNH. Alternatively, the Legislature could enact new legislation directing such a move. Under such a scenario, the competitive affiliate would operate as a merchant owner of the facilities and PSNH would then obtain default service for its default service customers in the same manner currently used by Unitil Energy Systems and Liberty Utilities. This approach can be considered a variation on a "sell the assets" approach with the difference being that the "buyer" in this case would be an affiliated company and the price at which the assets would be transferred would be governed by the Commission's administrative rules, specifically the Puc 2100 rules. The transfer of capital assets from a distribution company to an affiliate is subject to the following pricing provisions:

> *Puc 2105.09 Transfer of Goods, Services, and Capital Assets.*
>
> *(a) To the extent that these rules do not prohibit transfers between a distribution company and its affiliates, all such transfers shall be subject to the following pricing provisions:*
> *(1) A distribution company may sell, lease, or otherwise transfer to an affiliate, including a competitive affiliate, an asset, the cost of which has been reflected in the distribution company's rates for regulated service, provided that the price charged the affiliate is the higher of the net book value or market value of the asset;*
> and
> *(7) For purposes of this section, the market value of any asset sold, leased, or otherwise transferred, shall be determined based on the highest price that the asset could have reasonably realized after an open and competitive sale.*

As discussed earlier in the report, certain of PSNH's generating assets would be expected to have a market value in excess of net book value, while others would be expected to draw less than net book value if sold on the market. Taken as a whole, however, the fleet would be expected to realize an amount less than net book value through a competitive sale process. Thus, a transfer of the entire generation fleet to a competitive affiliate would most likely be achieved at net book value. A transfer of the generating assets at net book value would leave PSNH customers indifferent in that there would be no above-book or below-book asset sales revenues to manage from a rate perspective. That could be viewed as one advantage of a transfer of the assets to a competitive affiliate of PSNH. Another advantage is timing. By forgoing the need to issue an RFP to solicit bids, conduct site visits, receive and evaluate bids, negotiate sales agreements, etc., a transfer of assets to an affiliate could be achieved in a much shorter timeframe than soliciting competitive bids.

One complicating factor in such a transfer scenario is the existing power purchase agreements PSNH has with the Burgess BioPower facility in Berlin, New Hampshire and with the Lempster Wind facility in Lempster, New Hampshire. As these agreements are not fixed, depreciable assets having a specific net book value on PSNH's books, the dollar value at which they could be transferred to an affiliated company is not as clear, though sales of power purchase agreements are not uncommon in the electric industry.

Cost Recovery Issues in the Event of Sale or Retirement

Currently, cost recovery with respect to PSNH's generation facilities is governed by the following New Hampshire statutes (with the cost recovery sections italicized):

Regarding sale or retirement:

> **369-B:3-a Divestiture of PSNH Generation Assets.** – The sale of PSNH fossil and hydro generation assets shall not take place before April 30, 2006. Notwithstanding RSA 374:30, subsequent to April 30, 2006, PSNH may divest its generation assets if the commission finds that it is in the economic interest of retail customers of PSNH to do so, *and provides for the cost recovery of such divestiture.* Prior to any divestiture of its generation assets, PSNH may modify or retire such generation assets if the commission finds that it is in the public interest of retail customers of PSNH to do so, *and provides for the cost recovery of such modification or retirement.*

Regarding the Scrubber at Merrimack Station:

> **125-O:18 Cost Recovery. –** If the owner is a regulated utility, the owner shall be allowed to recover all prudent costs of complying with the requirements of this subdivision in a manner approved by the public utilities commission. During ownership and operation by the regulated utility, such costs shall be recovered via the utility's default service charge. In the event of divestiture of affected sources by the regulated utility, such divestiture and recovery of costs shall be governed by the provisions of RSA 369:B:3-a.

In any circumstance that involves PSNH selling or retiring some or all of its generating plant and entitlements, the strong likelihood exists that there will be a remaining amount of net book value either not covered by the sales proceeds realized or otherwise remaining to be recovered. The questions that immediately arise are:

- Who should pay those costs?
    - Customers?
    - Shareholders?
    - Some combination?
- By what method should those costs be recovered?
    - Stranded cost charge?
    - Distribution charge?
    - Some other non-bypassable charge?
    - Some other method?
- Over what period of time should those costs be recovered?
- Should there be recovery both of (depreciation) and on (return) the net unrecovered book value?
- What rate of return should be applied to the net unrecovered book value?
    - In the event of a sale
    - In the event of retirement

Rate Impacts Associated with Various Levels of Asset Values

The answers to the questions raised above are not simple nor are they expected to have unanimous answers among the various stakeholder groups. In considering those questions, an important component of this study is the possible level of default service rates over the near-term to mid-term period for those customers who remain on PSNH's default service rate, Rate ES. As described in previous sections, our analysis indicates that PSNH's default service rate will likely remain well above market and, depending on scenario, that disparity between the market price and PSNH's default service rate could become even higher than the approximately 2 cents per kWh that exists, currently. One financial mechanism associated with a potential divestiture or retirement is one used in the PSNH restructuring proceeding: securitization of stranded costs. While we do not take a position on that particular policy option in this investigation, it is one that has been used successfully in the past during electric restructuring. It is widely used in the financial industry, especially in the mortgage business, but also for non-mortgage assets such as credit card receivables and student loans.

As we note in the section titled Potential Legislative Changes, the retirement or divestiture of PSNH's generating assets and the use of securitization would need legislative changes to implement. Our purpose herein is to provide an overall rate context for PSNH default service customers based on a potential divestiture or retirement of PSNH's fossil-hydro plants under various asset values and cost recovery assumptions. The stranded cost analysis assumes that PSNH recovers all unrecovered net book value of the generation assets as stranded costs. This analysis is not meant to say that any one resulting rate scenario is more likely than another, but rather to provide context concerning rate impacts, should PSNH's default service rate result from a competitive bid process such as used by UES and GSEC, and to recognize what the combined rate impact could be as an asset sale or retirement could result in a new stranded cost charge. All assumptions used in this analysis are, therefore, illustrative and are used solely to help frame the discussion regarding cost recovery and rate impacts.

The four scenarios Staff evaluated assume that the asset sale price is either: 1) the full net book value of the fossil-hydro plants, 2) zero, 3) \$100 million or 4) \$300 million. Staff used the net book value of the generation plant as of March 31, 2013, \$673,722,000, though we recognize that value will change if, and when, any divestiture or retirement would take place. Though sales of PPAs were common during electric restructuring, Staff did not attempt to estimate any potential market value associated with the Lempster Wind PPA or the PPA with the Burgess BioPower project. A term of 15 years was used for the recovery period of the stranded costs resulting from the net book value minus the sales price of the assets and we varied the interest rate from 2% to 6%. While the debt markets are favorable currently, the actual interest rate for any use of securitization would depend greatly on the financial markets at the time as well as the amount securitized, the size in dollars and the number of tranches to be issued, the special purpose entity or vehicle created to facilitate the transaction and numerous other important legal and structural aspects needed to guarantee a low financing rate and recovery of the cash flows.

For illustrative purposes, we used all retail load (i.e., all PSNH customers) in the denominator, 7,800,000 MWh, over which to recover any potential stranded costs. If the current load that has migrated to competitive supply was removed from the calculation, the resulting rate would essentially double, assuming 50% load migration. The stranded cost rate we calculate, averaged over a 15-year term, varies from a low of $0.00369 per kWh based on $373,722,000 of "stranded costs" ($673,722,000 net book value - $300,000,000 asset sale price) and a 2% interest rate to a high of $0.00870 per kWh if the sales proceeds for the assets was zero and the interest rate was 8%. Of course, a sale that results in full recovery would produce no stranded costs, but that outcome appears highly unlikely based on our analysis of the value of PSNH's generating units at this time.

If the plants were divested or retired, PSNH would still need to procure power for its default service load. If it did so in a manner similar to New Hampshire's other electric companies, i.e., through a competitive solicitation, we believe it would be able to procure power at similar or slightly lower rates than UES or GSEC. In today's market, that would equate to around $0.07000 to $0.07500 per kWh. These default service rate estimates combined with the stranded cost estimated rates would result in a combined rate of $0.07369 per kWh to $0.08370 per kWh. As stated above, if customer load that has migrated to competitive supply were excluded from the denominator, then the overall combined effect on default service customers would be higher as the "stranded cost" rate would be twice as high as described above. Of course, markets can and do change over time, sometimes dramatically, and these rates are provided to give some indication of outcomes that could be expected based on the assumptions used in our rate impact analysis.

The lowest and highest results of the stranded costs scenario analyses are shown in Table 6 in combination with default service rates of $0.070 cents per kWh and $0.075 cents per kWh.

Table 6

	Low Cost Scenario	High Cost Scenario
Net Book Value	$673,722,000	$673,722,000
Asset Sale	$300,000,000	$0
Potential Stranded Cost	$373,722,000	$673,722,000
Average Annual Cost	$28,811,184	$67,883,571
Stranded Cost Rate per kWh with All Retail Load of 7,800,000 MWh	0.00369	0.00870
Default Service Rate per kWh	0.07000	0.07500
Overall Combined Rate Effect per kWh	0.07369	0.08370

Some of the questions posed above could be best addressed through a collaborative process, but it is likely that such a process would be very lengthy. Even with a lengthy process involving full participation of interested stakeholders, there is no guarantee of success. Certain questions may be answered with others remaining open to dispute. What follows is a summary of views of the stakeholder groups on the areas at issue.

Stakeholder Discussions

In addition to PSNH, Staff met with a broad set of stakeholders, including representatives of power producers, competitive suppliers, and large customers. We also met with a number of environmental groups. We consulted as well with the Office of Consumer Advocate, the New Hampshire Department of Environmental Services and the Governor's Office of Energy and Planning. We found the views of the stakeholders with whom we met candid, constructive, and informative.

PSNH Asset Values

With the exception of PSNH, these representatives as a group gave little basis for confidence that the PSNH fossil units have a place in the regional marketplace. The consensus was that the units are not economic today and have no substantial likelihood of becoming so in the foreseeable future. Some identified location the plant sites as an asset and there was a general consensus that the hydro facilities have positive value that partially offsets the negative value of the fossil units.

Sustainability of Default Service at Current Rates

There was also a general consensus among stakeholders, excluding PSNH, that default service is not economically sustainable.

We addressed with stakeholders generally the question of how the high costs of default service affect the development of competition. We specifically asked whether the current large gap (over 2¢/kWh) between PSNH default service and competitive suppliers did not present an opportunity for development of more robust competition for residential and small commercial customers; *i.e.*, a strong signal of the benefits of moving to a competitive supplier. We contrasted this circumstance in PSNH's serving area with the much smaller gaps that exist in the case of the other two major state distribution companies. Acknowledging the gap's advantages, the competitive suppliers with whom we spoke still favored a prompt withdrawal of PSNH from the supply function, citing factors such as the chilling effect that an incumbent wires company can have on development of competition.

The factors commonly cited included:

- The fact that other New England coal units, some of them more efficient than those of PSNH are already being retired
- Recent sale prices of more efficient coal units produced very low values
- EPA and RGGI issues will further contribute to demise of PSNH coal
- There is a very high likelihood that shale gas will keep regional gas prices at strongly competitive prices
- Spikes that the New England region experienced this past winter likely represent a short-term phenomenon, as pipeline infrastructure is expected to expand in response to market opportunities to move gas to the region.

PSNH Units as a Hedge

Neither the wholesale generators nor the retail competitive suppliers observed significant grid reliability value to continuing operation of the PSNH fossil units. PSNH did not proffer this advantage either. PSNH, alone among the stakeholders, placed significant emphasis on the value of the fossil units as a hedge against natural gas cost spikes. The other stakeholders recognized recent conditions, but those expressing opinions about the future of natural gas markets tended to believe that transportation system constraints, rather than supply, are key, and that they are likely to be ameliorated in the near future. Moreover, general beliefs are that the costs to default customers for the "insurance" provided against gas price spikes exceed their value, and that the issue is in any event more appropriate for treatment at the regional (ISO) level.

Options for Dealing with the PSNH Generation Fleet

There was a strong consensus among stakeholders that PSNH should be out of the generation business, with some thought by government stakeholders that options for retaining the hydro facilities might prove beneficial. There was no consensus on the methods (*e.g.*, a competitive divestiture process, transfer to an affiliate, or retirement) to accomplish an exit. As noted above, however, it was clear that stakeholders consider that forcing the units to compete in the marketplace would lead to their retirement.

Establishing a level playing field (vis-à-vis PSNH as an incumbent, rate protected competitor) emerged as a major concern of the wholesale generators. They observed that a regulatory regime providing for full cost recovery raises concern about PSNH motivations in bidding its units into ISO markets. The concern is that PSNH behavior (particularly given that its plants are not often competitive in those markets) may be influenced by a belief that costs unrecovered in the markets will be recovered in retail rates for default service. They would like to see a process that requires PSNH to use competitive bidding to secure resources needed for providing default service

Stranded Costs

Whether, how and from whom stranded costs should be recovered produced no consensus. The issue can perhaps be viewed as less central to those who operate at the wholesale level. Retail suppliers expressed a general aversion to adding significant wires charges to those they would like to serve. Some expressed the view that imposing substantial stranded costs as a wires charge would cause businesses to leave New Hampshire. Some expressed strong opposition to recovery of scrubber costs by any end users other than those taking default service, others raised substantial concerns about whether such costs were prudent in the first place, and one inquired into whether a PSNH bankruptcy should be considered an option. Some did support a sharing of stranded costs among a broad range of customer groups and PSNH, including the use of cost mitigating measures, such as securitization (recognizing low interest costs prevailing in the financial markets).

The lack of consensus and the strength of opinions on the question of stranded costs make clear that resolving it will prove contentious.

Some observed that the question of stranded costs could be avoided entirely by a transfer of the fleet to PSNH at remaining book cost, observing that the idea might have appeal to PSNH, which has stressed that the units continue to have value in natural gas-constrained market conditions. This appears not to have serious potential. PSNH has not asserted that the units have value equal to or approaching book value. Moreover, those who have made this observation also believe that the units have negative value as a whole, which would make this an unappealing alternative from the outset.

Environmental Issues

The stakeholders recognized that environmental risks add to the pessimism about the future of the PSNH fossil units. The opinions about continued operations, however, largely focused on economic and not environmental consideration. The stakeholders representing environmental interests very much focused their observations on the economics of the units. They too noted that regional coal assets have either been retiring or selling for very little, which strongly evidences the market's view that the units cannot compete effectively. Some of the other points addressed by their representatives included:

- Future RGGI prices in the $5 per allowance range will generate a further direct adder to coal dispatch cost
- MATS problems at Schiller will be a major contributor to its retirement
- Natural gas prices are expected to remain low, particularly as the transportation constraints affecting New England are addressed
- The Merrimack scrubber should not be considered as providing an environmental benefit to all of New Hampshire, as opposed to a fairly small region of the state.

Potential Legislative Changes

Many existing New Hampshire statutes were written to pertain to then-existing conditions with respect to electric industry restructuring, and particularly with regard to conditions in PSNH's service territory. As market changes have taken place since those laws were enacted, attempts to apply those statutes to current conditions can be viewed in some instances as either illogical or impossible. What follows is a discussion of certain statutes that may require legislative review and modification. By no means is this an all-inclusive list. Rather the discussion serves to highlight major areas of interest.

Divestiture of PSNH Generation Assets Under RSA 369-B:3-a

Throughout the process of restructuring, the New Hampshire Legislature has proactively sought to guide the structure and timing of restructuring events as pertaining to PSNH through highly detailed statutory enactments. This role peaked in the early 2000's, both with the approval of PSNH's rate reduction bond packages, with the concurrent requirement for PSNH to divest its interest in Seabrook Station, and the Legislature's efforts at slowing down the divestiture of PSNH's fossil-fueled and hydroelectric generating assets. This effort at delaying the full impact of restructuring on PSNH's operations culminated in the passage of RSA 369-B:3-a in April 2003, in the wake of the California energy crisis. The statute specifies that, following April 30, 2006, "PSNH may divest its generation assets if the [C]ommission finds that it is in the economic interest of retail customers of PSNH to do so, and provides for the cost recovery of such divestiture." (Emphasis added). RSA 369-B:3-a further specifies that "[p]rior to any divestiture of its generation assets, PSNH may modify or retire such generation assets if the [C]ommission finds that it is in the public interest of retail customers of PSNH to do so, and provides for the cost recovery of such modification or retirement." (Emphasis added).

Given the present circumstances, the Legislature may wish to review RSA 369-B:3-a, to determine if any modifications to the statute are necessary.

Definition of Stranded Costs

In conversations regarding the future of PSNH's generation fleet, much of the discussion concerns the subject of "stranded costs." It is important to understand, then, what stranded costs are and how they are currently defined in New Hampshire law. As stated earlier, stranded costs can generally be defined as the difference between costs expected to be recovered under regulated rates and those recoverable in a competitive environment. In New Hampshire law, stranded costs are defined in RSA 374-F:2, IV as follows:

> "Stranded costs" means costs, liabilities, and investments, such as uneconomic assets, that electric utilities would reasonably expect to recover if the existing regulatory structure with retail rates for the bundled provision of electric service continued and that will not be recovered as a result of restructured industry regulation that allows retail choice of electricity suppliers, unless a specific mechanism for such cost recovery is provided. Stranded costs may only include costs of:

> (a) Existing commitments or obligations incurred prior to the effective date of this chapter;
> (b) Renegotiated commitments approved by the commission; and
> (c) New mandated commitments approved by the commission, including any specific expenditures authorized for stranded cost recovery pursuant to any commission-approved plan to implement electric utility restructuring in the territory previously serviced by Connecticut Valley Electric Company, Inc.

The "effective date of this chapter" referred to in subsection (a) above was originally 1996, with the most recent change to the statute occurring in 2003. With respect to a potential sale or retirement of PSNH generation plants, especially considering post-statute capital additions, none of the subsections of the law as it currently exists would appear to allow for inclusion of any unrecovered net book value of the plants as stranded costs. That is an important concept because RSA 374-F:3, XII provides that stranded costs be recovered through a "nonbypassable" charge, i.e., from all customers of a utility, regardless of whether they receive default service from the utility or receive service from a competitive supplier. Given the current statutory stranded cost definition, it does not appear that any stranded costs arising from a sale or retirement of PSNH's plants would be eligible for recovery through such a nonbypassable charge, absent a legislative change, meaning that default service customers could be left with that cost burden.

Electric Rate Reduction Financing (a/k/a Securitization)

Electric industry restructuring in PSNH's service territory was accomplished through a combination of the *Agreement to Settle PSNH Restructuring* (Restructuring Settlement) considered by the Commission in Docket DE 99-099 along with the enactment of certain enabling statutes. Chapter 369-B of the New Hampshire Revised Statutes Annotated provided for the issuance of bonds with a dedicated and prioritized revenue source as a method for PSNH to recover a category of its stranded costs arising from the Restructuring Settlement.[42] The dedicated revenue source combined with the specific requirements of the bonds created an attractive investment vehicle for bond investors and allowed for lower interest rates than what would be considered "standard issue" utility bonds. These bonds have been referred to in the past as "rate reduction bonds" or "securitized bonds."

Considering the potential magnitude of stranded costs—depending on the future path taken with respect to PSNH's generation fleet—securitization may be an avenue worth pursuing. However, as the enabling legislation in Chapter 369-B dealt specifically with the particulars of DE 99-099, the statutes would need to be revised to accommodate the present day circumstances.

PSNH's Provision of Default Service

RSA 369-B:3, IV(b)(1)(A) sets forth current requirements for PSNH's provision of default service:

[42] The last of the rate reduction bonds from DE 99-099 were extinguished during the second quarter of 2013.

> From competition day until the completion of the sale of PSNH's ownership interests in fossil and hydro generation assets located in New Hampshire, PSNH shall supply all, except as modified pursuant to RSA 374-F:3, V(f), transition service and default service offered in its retail electric service territory from its generation assets and, if necessary, through supplemental power purchases in a manner approved by the commission. The price of such default service shall be PSNH's actual, prudent, and reasonable costs of providing such power, as approved by the commission.

As prescribed in the statute, PSNH must use its generation assets combined with supplemental purchases until such time as it completes the sale of its fossil and hydro assets. The Legislature may need to revisit these requirements if a sale of those assets were to take place, or if customer migration creates too much upward pressure on the default service rate.

Conclusions and Recommendations

Based on our analysis of the drivers of electricity prices in the region and the costs, both fixed and variable, associated with PSNH's generation in the near-term, and our discussions with stakeholders, Staff does not believe the status quo is a viable option going forward. Recommendations we discuss below are complex and will require the involvement of a wide range of parties. Changes resulting from the recommendations may not occur in a short timeframe, but, ultimately, they are ones that will reduce the uncertainty currently pervading numerous aspects related to New Hampshire's electricity market.

A theme that occurred throughout our meetings with stakeholders was the need for New Hampshire to complete electric restructuring. That viewpoint was expressed to us with the recognition that such a change could result in the creation of future stranded costs for PSNH customers or that it may result in less retail competition, at least in the short term. PSNH expressed its belief that their generating units provide a valuable hedge to today's volatile natural gas-driven electricity market, especially in New England. The default service rates of PSNH have been above the default service prices of New Hampshire's other electric utilities for the last 4 years and that disparity has grown to over 2 cents per kWh recently. The belief that the PSNH "physical hedge" may someday be "in the money" again as it was in the early years after electric restructuring is not supported by our analysis and PSNH provided no analysis or forecasts that would allow one to reach that conclusion. Instead, we are confronted with an ever challenging regulatory environment in which customers of New Hampshire's largest utility—predominantly residential—are faced with paying an ever increasing portion of PSNH's fixed costs as more load migrates to competitive supply and the uncertainty, in the form of potential yearly legislative proposals, concerning electric prices and policy for New Hampshire's largest electric utility.

Many important questions remain to be answered. We believe that they require prompt answers, given the circumstances. The Commission should consider opening a proceeding to receive comments and recommendations from PSNH and other stakeholders regarding this report and the issues it addresses. Particular focuses should include the following:

- Whether PSNH's default service rate remains sustainable on a going forward basis
- What "just and reasonable" means and what it requires with respect to default service in the context of competitive retail markets
- Analytically supported views of the current and expected value of PSNH's generating units under an appropriately designed range of future circumstances.
- What means exist to mitigate and address stranded cost recovery

The valuations of PSNH units as described in this report are preliminary. They indicate a lack of competitiveness across a wide range of assumptions. However, definitively assessing the costs and benefits of some options depend on reasonably firm value estimates. Securing that firmness requires more work than our report entailed. The Commission thus may also want to consider requiring an independent asset valuation process undertaken at a more detailed level.

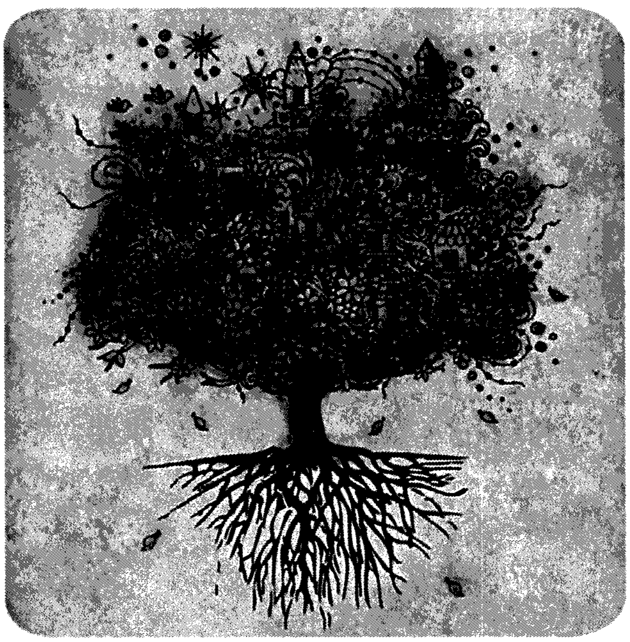
We also recommend that consultation with legislative and executive leadership begin. We also recommend that PSNH be asked to bring forth immediately proposals that would address a transfer of energy supply assets to an affiliate in accord with the optimistic views that the company has expressed with regard to the value of those assets.

A5

DEFG

Consumer • Energy • Performance

Engaging and Enrolling Low Income Consumers in Demand Side Management Programs



By: Cindy Boland O'Dwyer

A research project commissioned by the DEFG Low Income Energy Issues Forum

June 2013

Introduction

Energy providers (utilities, competitive providers and others) have long struggled to effectively engage with low income customers[1] and also to meet business requirements for the management of bad debt and debt recovery. Decades of customer program research has shown that low income energy customers are often more difficult to reach due to a number of factors, including but not limited to: limited access to customer information, needs that differ in degree or complexity compared to other customer groups (e.g., low income customers are often renters, and thus do not control heating and cooling or own the appliances), difficulties making contact via traditional channels, regulatory requirements, and complex intersections with energy assistance and other low income programs such as budget billing.

Moreover, the challenges of serving low income customers are expected to be compounded by flat or declining levels of assistance even as the need for more assistance continues to grow. Beyond assistance programs, there are specific enrollment targets for low income customers as part of regulatory oversight of demand side management (DSM) programs—the very programs that could most help low income customers manage their energy bills and lower their spending over time—that are oftentimes not being met, even as the targets continue to rise.

In the spring of 2013, DEFG created the "Low Income Energy Issues Forum (LIEIF)," comprised of consumer advocates, regulatory commissioners, utilities and energy suppliers, government agencies and non-profit administrators, and others, as a means to look anew at questions pertaining to engaging with and serving low income customers.[2] Current DEFG research focuses on consumer behavior, incorporating new channels and technologies in consumer programs, and integrating consumer offerings including programs, rate designs, notifications and customer service touch points. DEFG research and other sources confirm that there are significant differences in how to best serve and engage with low income customers as a defined segment, which the Forum was established to address.

The Forum is intended to be exploratory and collaborative, and is focused on three critical issues:

- Considering Ways to Increase Enrollment of Low Income Consumers in DSM Programs
- Policies & Practices: Bad Debt and Debt Recovery, and Consumer Debt Management
- Developing a Landscape Perspective, Future Scenarios and Case Studies for Leveraging Limited Assistance Funds

This paper captures the Forum's work on Issue 1. Summarizing contributions from practitioners in the field and input from the Forum members, the paper highlights challenges and explores different approaches to engaging and enrolling low income consumers in DSM programs. The paper concludes with recommendations and further areas of inquiry.

Summary of Findings

Traditional marketing methods (bill inserts, direct mail campaigns, radio advertisements) have often proven unsuccessful for low income DSM enrollment. Challenges can be attributed to a lack of knowledge regarding low income customers and their specific needs, and thus the wrong offerings being marketed. There is also a lack of targeted marketing strategies that ensure engagement with this harder-to-reach group. Moreover, every dollar matters to low income families, so the benefits of DSM measures must be clearly quantified and communicated. These customers do not want to take on any risk.

[1] The Low Income Home Energy Assistance program (LIHEAP) statute establishes 150 percent of the poverty level as the maximum income level allowed in determining LIHEAP income eligibility, except where 60 percent of state median income is higher. Income eligibility criteria for LIHEAP may not be set lower than 110 percent of the poverty. See: http://www.acf.hhs.gov/programs/ocs/resource/liheap-eligibility-criteria.

[2] The concepts presented in this paper are derived from practitioner presentations and experiences, and webcast discussions among the Low Income Energy Issues Forum. Please note that the inclusion of a concept or a proposal does not imply the support of any or all of the members of the Forum. The work is intended to be exploratory. DEFG LLC is responsible for the final written product that is released to the public.

There are indeed benefits to increased DSM enrollment for both providers and customers. Providers need to meet ever-increasing energy efficiency targets, better manage grid resources and increase customer satisfaction ratings among low income populations. For the customer, DSM programs can empower the members of a household to better understand how and when to use energy to their advantage, and create opportunities for lower bills.

To address the shortfalls of traditional methods, a new low income consumer marketing model must be considered. Four practitioners have presented distinct but complementary approaches to engaging and enrolling low income consumers in DSM programs, recognizing that low income populations have distinct needs and preferences.

Below are highlights from the four approaches. Each approach is discussed in greater detail in the following pages.

Marketing & Outreach Approach • The key to continued engagement is building relationships and trust • There is a need to recognize socio-cultural dynamics • It is essential for service providers to be imbedded in the community and to interact in a personal way • Low income populations are consistently loyal	**Behavioral Approach** • The quality of a customer's experience influences a wide range of behavior (e.g., loyalty or advocacy) • The ultimate goal is for customers to have a "signature experience"—a meaningful differentiated expression of what a service or product or company stands for • A prioritized set of behavioral outcomes sets the stage for influential program design
Partnership Approach • Critical to understand funders' goals (utilities = savings; state & DOE = production; cities/corps. = carbon reduction) • Must leverage funds / make dollars work • Defined processes and procedures must be in place (e.g., good reporting is essential to track results) • Stakeholder communication is key	**Transactional Approach** • Think holistically to move from a binary look at transactions toward a complete customer experience • Customize interactions—provide actionable information, use customer preferred channels, provide flexible bill options • Leverage technology to achieve business goals and deliver better low income customer experience.

Considering the experiences and observations of the practitioners and Forum members, DEFG offers the following general recommendations:

- Providers must customize DSM program to meet low income customers' lifestyles and needs (e.g., multi-generational families, renters)—the offering needs to make sense and offer value
- Communications need to be straightforward regarding a household's potential energy savings
- High-touch interactions are critical to relationship building with low income populations.
- A linkage between cash assistance, bill pay and energy management must be strongly established
- Customer cost savings achieved through energy efficiency measures should lead to lower energy bills and help cover or offset any gaps that may exist from diminished assistance funding
- Providers should able to serve a broader group of customers with potentially the same cost infrastructure

Additional discussion regarding recommendations and further areas of inquiry can be found in the closing section of the paper (see pp. 10-12).

Marketing & Outreach Approach by RHA[3]

Working with all the large regulated energy utilities in California, RHA administers weatherization, home energy performance, and multi-family and commercial business energy efficiency programs. RHA also designs and implements education programs for utility customers. A key piece of their approach and success is how they market to and interact with low income populations. Through their regional offices, RHA supports an emphasis on local partnerships for outreach, education and service delivery. Emphasizing a wide-angle view, RHA observes low income populations as a sizeable emerging market with considerable purchasing power that requires a new high-touch marketing strategy.

Top-Line Findings

RHA provides examples of socio-cultural dynamics for low income populations, which include limited or no English proficiency, having more children, multi-generational living situations, and potentially feeling prideful. With regard to technology, there may be limited home web access but typically high levels of mobile access. There are also a lower number of electronic appliances (dishwasher, washer/dryer) but it is common to own large televisions and game consoles. RHA asserts that these characteristics are all reasons why low income populations typically do not respond to mainstream media and marketing campaigns.

Beyond economics, there is an absolute need to understand the low income customer. RHA emphasizes the importance of companies becoming imbedded within the community. Multi-national corporations (e.g., Walmart, Chase Bank) have realized the significance of "becoming native" through retail locations in underserved areas. Research, moreover, has shown that low income segments are consistently loyal with brand and companies. Thus, strong reliance upon word-of-mouth recommendations within the community play a critical role.

It is essential to consider the customer's perception of an offering, which requires knowing the customer and creating a meaningful experience for the customer. In addition to the socio-cultural dynamics noted, it is also important to know more general demographic information, such as ethnicity, age, home ownership / renter, employment, etc. The key questions are: what can you learn about customers and how to use it?

RHA notes that customer data mining is not adequate alone but must be combined with an understanding of the customer. For electric utilities, RHA employs a marketing and education team well trained in speaking to utility service offerings but also in cultural competency and outreach best practices. There is a huge impact when a well-trained

[3] RHA, Inc. provides program management and outreach services throughout California for clients seeking to advance behavioral change and technology adoption in the mass market.

customer agent is at the door or on the phone delivering high-quality customer interactions. Through these interactions, agents can learn the customer's preferred methods of communications and begin to use more efficient and less costly channels such as email or text. These channels become more successful following a high-touch interaction where a relationship has been formed. Relationships between utilities and their customers can be further strengthened through community partnerships. The low income population can begin to recognize the utility as a familiar and vested member of the community.

Necessary steps towards acquiring low income customers and ultimately satisfied customers are: to be "on the ground," to interact within the community in a personal way, to build relationships and trust, and to deliver products and services that have a positive impact.

The return on investment is big and includes:

- Higher program participation
- Increased energy management (education required)
- Higher customer satisfaction
- Development of mutual trust and capability
- Favorable image in community (has a high value, powerful word-of-mouth)

RHA explains that within low income populations, customer satisfaction is a guiding principle—the most powerful predictor of future revenue. The relationship can move from purely transactional to more powerful interactions with a path to additional engagement opportunities. A real win for an energy provider is for a low income customer to be eager to engage and willing to learn of opportunities to better manage energy usage and costs.

This engagement strategy presented by RHA has produced real results in California. PG&E noted that when low income customers are truly supported, they feel in control and cared for, and accordingly are much more likely to subscribe to programs. When there is trust, multiple opportunities follow.

Challenges & Inquiries

Several challenges were noted among the Forum members. One utility mentioned trying to nail literacy equivalent so their program materials can be consumed by the larger population. There was an inquiry into integration challenges with community-based organizations, third-party providers and channel partners. These relationships are necessary, and they require time spent on training and managing content. Performance metrics were proposed as a sensible measure for ensuring results. Another challenge noted is that many low income energy customers are renters, so their appliances and building characteristics may be beyond their control. Many providers are currently exploring opportunities to engage with customers in multi-family dwellings. This is an issue ripe for further research and attention.

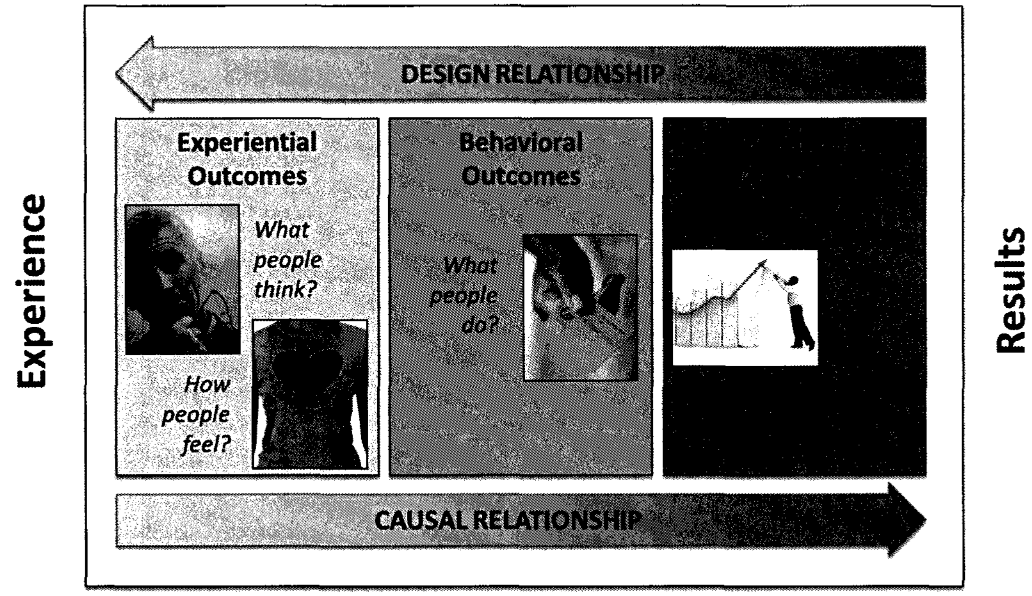
Behavioral Approach by Customer Innovations[4]

Customer Innovations (CI) asserts that the quality of a customer's experience influences a wide range of behavior. For example, an experience can lead to a loyal customer who provides a reliable revenue stream, to an engaged customer who responds positively to new offerings, or to an advocate that provides positive referrals to prospective customers. Companies often focus on how they deliver an experience rather than how customers have an experience—CI stresses that how customers have an experience can influence positive and profitable behavior. The strategy here is to influence low income DSM program adoption through design.

[4] Customer Innovations, a design firm based in Atlanta, Georgia, has a uniquely structured approach to designing products, services, and experiences that positively influence behavior.

Top-Line Findings

CI recommends looking first at desired business outcomes or goals. These goals should be measurable and involve steps that are actionable. Below is an illustration of the flows from experience to results and in the reverse from results to experience. CI explains that the design relationship starts with the consideration of desired business outcomes.



Thus, defining a prioritized set of behavioral outcomes sets the stage for influential design. The first objective is "Focus"—to clarify and prioritize the specific behaviors that drive desired business results. The next objective is "Understand"—to develop a set of "Influence Profiles" that identify specific levers for generating the desired behaviors. This involves a good look at customer segmentation and profiles. Here we are focused on low income consumers, so the marketing strategy and messaging must be tailored for this population. CI asserts that traditional voice of the customer approaches do not provide sufficient insight with this consumer group.

The final objective is "Design"—to create an "Influence Playbook" that describes specific design and execution interventions that will generate desired behaviors. Again, it is experiences that influence behaviors—both internal and external. With internal experiences, people are influenced by their own perceptions, thoughts and feelings. The external experience involves interactions between a person and their environment. Humans are very adept at getting the gist of a situation and in general resist recognition of incremental changes. In fact, CI argues that incremental service quality improvements go largely unnoticed.

The elements of creating a "signature experience" include:

- *Message*: Great stories have a strong premise, an ideological center that provides meaning
- *Conflict*: *There is no story without conflict*! Meaningful stories involve a struggle to attain, defend or regain harmony
- *Characters*: You need a hero and villain with opposing agendas, most stories also include supporters, benefactors, and beneficiaries
- *Signature Difference*: You need a small set of signature experience elements that reinforce a storyline about what makes you unique and compelling

Thus, it is important to move "beyond better sameness" and create a meaningful differentiated expression of what your service or product or company stands for—this is the "signature experience." Moreover, the experience must be delivered in a way that builds a strong emotional bond with customers. Perhaps empathy or patience must be exhibited. It is necessary to get the customer's attention, but a balance must be maintained between making it easy for customers to get the gist and capturing the customer's attention by creating a signature experience—this calls for maintaining simplicity while simultaneously injecting meaning.

CI identifies the following analyses as a starting point for how to influence low income customer behavior towards DSM adoption:

- What are the customer benefits for adoption of DSM?
- How do customers make sense of options?
- What barriers might be there and how might we overcome them?
- What are the channel choice considerations?
- Can adoption be broken into a series of small behavioral steps?
- What will catch their attention?
- How can programs reinforce the messaging and behavior?

Challenges & Inquiries

Customers are often on the wrong rate or tariff due an inability of the provider to communicate the benefits of an alternative plan in a meaningful yet simple manner. Providers also cite challenges with how to communicate with customers around how to use their energy differently—customers cannot unceasingly be told to use less energy. There needs to be a new message.

Partnership Approach by Energy Outreach Colorado[5]

Energy Outreach Colorado (EOC) programs include bill payment assistance, energy efficient projects, efficiency education and advocacy. EOC is unique in that they are a non-profit and act as an operating foundation of sorts, raising funds from utilities and delivering programs for utilities. Relationships with utilities, subcontractors, private and public organizations, government and quasi-government agencies play important roles. An excellent demonstration of securing and leveraging funds is the "Garden Court" project in Denver, Colorado.[6]

Top-Line Findings

Partnerships and funding are crucial elements of EOC's success—strong funding relationships, processes and procedures must be in place. Funds may support one or more of EOC's programs. For instance, EOC provides grants to qualifying affordable housing communities and nonprofit facilities to pay for upgrades such as insulation, lighting and appliances.

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[5] Energy Outreach Colorado is the only independent, non-profit organization in the state raising money to help limited income Coloradans afford home energy. Since 1989, Energy Outreach Colorado (EOC) has distributed nearly $200 million to low income families across Colorado. Over 2012 – 2013, EOC will raise close to $20 million in funds. Funding comes from an array of source, including Xcel Energy, state funds, LIHEAP funds, city and county of Denver, oil and gas producers, corporate and individual donors, and others.

[6] Garden Court is a 15 building affordable housing complex with 300 units and annual total utility costs of $263,765 (usage - 189 kW, 1,588,301 kWh, and 14,808 Dth). Installing a variety of measures (boiler replacements, pipe insulation, common area lighting, new refrigerators, etc.) with a total project cost of $1,050,000, EOC was able to secure and leverage funds from five sources (state weatherization program – LIHEAP funds, City and County of Denver, EOC private funders, building owner – nonprofit affordable housing developer and Xcel Energy). The project has a predicted annual savings of $69,120 / 26% annual reduction. With leverage, there is a 6-year simple payback for owner.

EOC efficiency programs are quite diverse and include state-mandated natural gas DSM programs:

Multi-family Affordable Housing	**Nonprofit Energy Efficiency Program**	**Single Family**
Centrally heated and individually heated buildings—more than 5 units	Commercial buildings—shelters, food banks, transitional housing, administrative offices	Split between EOC and State Weatherization Program
Statewide provider for State Weatherization Program	City and County of Denver	Crisis Intervention Program—LIHEAP—Furnace replacement and repair
Utility DSM—Xcel Energy, Atmos Energy, Source Gas, Colorado Natural Gas—Custom Rebate	Utility DSM—Xcel Energy, Atmos Energy, Source Gas, Colorado Natural Gas—Custom Rebate	Utility DSM - Atmos Energy, Source Gas, Colorado Natural Gas —Prescriptive Rebate Levels —Xcel Energy/Black Hills Energy uses State Weatherization program
Also working with Rural Electric Cooperatives and Municipal Utilities	Large energy users that have not been targeted historically	Propane conversion program—Atmos Energy, Source Gas, Colorado Natural Gas —Rural communities—DSM funds
Ability to decrease customer bills, also split incentives	Used to "band aiding" systems	Creates unique access points to customers

With multi-family and large energy user non-profits projects, funds must be leveraged to maximize the measures installed. A creative example of leveraging funds is EOC's work with the Colorado Youth Corps to "blast" large buildings with low-cost measures and education. EOC drives the project process; otherwise building owners typically go with the lowest cost measures. A triangular contract is in place between EOC, the owner and subcontractors, so warranties can stay with the property owners. EOC maintains facility manager training post project completion to ensure savings goals are met. All post-work inspections and data tracking are conducted by the EOC staff. With utility relationships, EOC is under contract with the utility and the utility claims the savings.

Strong stakeholder communication and defined processes are a necessity for sustainable results. Below are key factors cited by EOC for the continued success of their mission:

- The subcontractor model (able to ramp up and down quickly)
- Leveraging diverse funds
- Understanding funders' goals (utilities = savings; state and DOE = production; cities/corps. = carbon reduction)
- Good reporting—producing and tracking results
- Always keeping the clients' needs first (balance building owners and residents, advocate on their behalf)

Challenges & Inquiries

With grant funding declining and lower energy prices, it is challenging to get projects completed. It is becoming increasingly difficult to demonstrate an adequate return on investment. This means that additional contributions from owners are needed. EOC is currently working with private funders and community development financial institutions to create a process for installation of measures using loan tools. The challenge is with selecting the right projects and organizations willing to take on the debt. EOC is designing a modified performance contract model to create working operating funding as part of the "performance contract" and redirecting those funds to the beneficiary organization. Evaluation of programs is also critical to future funding opportunities.

As a result of ARRA resources, there was a great push around energy efficiency which has now faded. EOC notes the importance of maintaining this momentum by educating regulators of the proven benefits and progress. EOC also highlights that this work calls for different regulatory parameters than "market rate" programs. Finally, EOC notes that these energy efficiency projects require intense case management, education and selling efforts than standard projects.

A forum member inquired whether there are any evaluation criteria or metrics in place to measure the impact of community-based organization actions. EOC starts education efforts six months ahead of a project and has seen impacts just from these efforts. EOC also looks at bill payment activity before and after project work, ensuring that customers are not falling into arrears. However, there are no comprehensive metrics in place. This is certainly a challenging piece.

Moreover, subcontractors and community agencies need to feel that they are truly a part of the process. There needs to be great caution exercised upon engaging these parties and when choosing to dismiss them—these decisions can result in wasted resources and the inability to achieve continuity and sustainable results.

Transactional Approach by DEFG

DEFG asserts that there is a need for utilities and retail energy providers to move from a binary look at transactions toward a more holistic customer experience tied to the entire utility enterprise. What if a magic wand could be waved to allow stakeholders to: dramatically reduce low income customer costs, raise low income customer satisfaction scores by 10 points or more, and hit DSM targets for the year with room to spare?

The vehicle to achieve these ambitious goals would be the introduction of "enhanced transactions" which leverage transactional platforms and new technologies to provide customers with more actionable information regarding their energy usage and more flexible and customized bill pay options. This approach is well suited to address the needs of low income customers given the number of transactions already occurring with the utility. Low income customers and third parties frequently transact with the utility to keep the lights on, ensure the allocation of cash assistance or credits, and establish payment arrangements. For your average utility and retail energy provider, these transactions account for the bulk of the contact volume and represent millions of dollars of costs. For low income customers, the traditional transactional approach represents a significant investment in effort and the allocation of scarce funds.

Top-Line Findings

Utilities and energy providers first need to take a close look at certain initial nuts and bolts improvements around low income customer communication and explore broad strategic thinking regarding the low income customer relationship. The overarching strategic objective would be for the utility or and retail energy provider to become "the trusted energy advisor." Trust is the key ingredient to build a two-way, interactive customer relationship.

The "trusted energy advisor" strategy entails a number of actions steps or strategic goals, including:

- Move from operational centric to customer centric model
- Become pro-active
- Employ multi-channel approach (anytime, anywhere communications)
- Move from segmented to personal messaging and offerings
- Think in a predictive way
- Become trusted
- Become valued
- Be transparent (employ accountability)
- Focus on the ease of doing business for the customer
- Evaluate performance

Trust will develop from meeting low income customers' need and preferences—essentially giving them an improved and more customized experience. Transactions such as budget billing and prepaid electric service (in jurisdictions where permitted)[7] are good examples of where to start—there is a direct link to leveraging smart grid, immediate potential for higher customer satisfaction, a natural bridge to a better managed and customized relationship with the customer, and potential for providers to meet business needs and regulatory requirements around program mandates and targets.

Consider budget billing. DEFG proposes the following steps to move from basic to enhanced transactions:

DEFG's "+ Strategy" for Budget Billing

Transaction + AMI	With advanced metering infrastructure, close-to-real-time data allows more information to flow to the customer when/how s/he prefers. Information is more relevant, and—through budget alerts—more actionable.
Transaction + AMI + Energy Conservation	Based on channel and frequency preferences, communications relating to energy conservation can be targeted to customer needs. S/he can act today and see the savings tomorrow.
Transaction + AMI + Energy Conservation + Behavior	Positive reinforcement will be key. A feedback loop should be incorporated and grounded into a pairing with an associative good, either economic or social. Context is important: make budget billing mainstream (not just a low income option). Be proactive and positive, rather than defensive and targeting people who need help. (Many customers want to manage bills).
Transaction + AMI + Energy Conservation + Behavior + Portfolio	Help customer optimize what they are already doing by connecting the transaction and platform to other parts of the portfolio or customer service offering to allow more savings and control. When the utility fully enables budget management—combining all the aspects of the customer portfolio—it will allow for personalized and predictive planning with individual customers. This is a trusted energy advisor model in action.

Transactions can present real opportunities for utilities and energy providers to better serve customers and meet business needs. Likewise, looking at prepaid electricity—this is a relatively new service that is gaining momentum as a 'smart' offering (2-way communication capability) where usage & account balance information can be shared with customers in near real-time via a feedback loop. Prepaid service relies on near-daily communication and fits with an anytime-anywhere payment paradigm with day-to-day energy and account balance management placed directly in the consumers' palm through email or text messaging. Consumers indeed place a premium on increased control and convenience, and smart devices have facilitated an exponential growth of digital communication and transactions.

Prepaid electricity has proven to reduce utility operational costs and bad debt write offs while providing customers the opportunity to use less energy and save money. DEFG, through its Prepay Energy Working Group, analyzed customer usage data (both post- and pre- enrollment) provided by the Oklahoma Electric Cooperative and the key finding was an energy usage reduction of on average 11% per household. With average monthly bills for OEC's customers at $146, this implies a $192 per year energy bill savings. Moreover, this energy use reduction is significant relative to other common energy efficiency measures and requires no upfront investment in equipment by the customer. While prepaid is not for everyone, there is a certain segment of customers that likes the offering and gives it high satisfaction scores.

The overarching idea is fairly straightforward—to leverage customer data and preferences to achieve business goals and deliver a better customer experience.

[7] Prepaid electric service is relatively new to the U.S. market but positioned to grow over the next several years with the introduction of smart metering infrastructure (offers two-way communications and technologies that reduce the cost and complexity of offering prepaid electricity). Some regulators and consumer advocates are opposed to, or wary of, the service as there are concerns related to service disconnection policies and consumer protections. Mention of prepaid service here does not imply the support of members of the Low Income Energy Issues Forum.

DEFG provides the following roadmap for achieving "the magic":

- *Be brilliant on the basics*: Focus first on process improvements
- *Start with what you know*: Start with the transactions, e.g., billing and payment options, that already exist
- *Move to new, enhanced transactions*: Leverage investments in AMI and customer systems to move towards prepay energy and other options
- *Understand that communication linked to data is key*: Invest in upgrading your data analytics and communications platforms
- *Develop a vision for customer strategy*: Develop a customer strategy that aligns enterprise-wide objectives with a future vision of the customer experience and value proposition over time
- *Rethink your metrics*: What are the best metrics that measure the outcomes—operational, business, customer experience and engagement—of the customer strategy?

Challenges & Inquiries

This approach requires an executive level look at the utility's customer strategy. While the concept is fairly straightforward, its execution requires a great deal of coordination and a more holistic approach to the customer than is currently being implemented. A forum member raised a question regarding consumer education around enhanced transactions. There are concerns about upfront customer contact costs and achieving scalability.

Recommendations & Further Areas of Inquiry

What has developed from the practitioner approaches is a new vision for low income customer engagement. Making the new model actionable requires asking critical questions at the onset. To illustrate, below is a series of questions intended to kick start the initial phase of a marketing effort to address a common challenge—low income customers are often renters in multi-family buildings with no control over building characteristics, heating and cooling, and appliances.

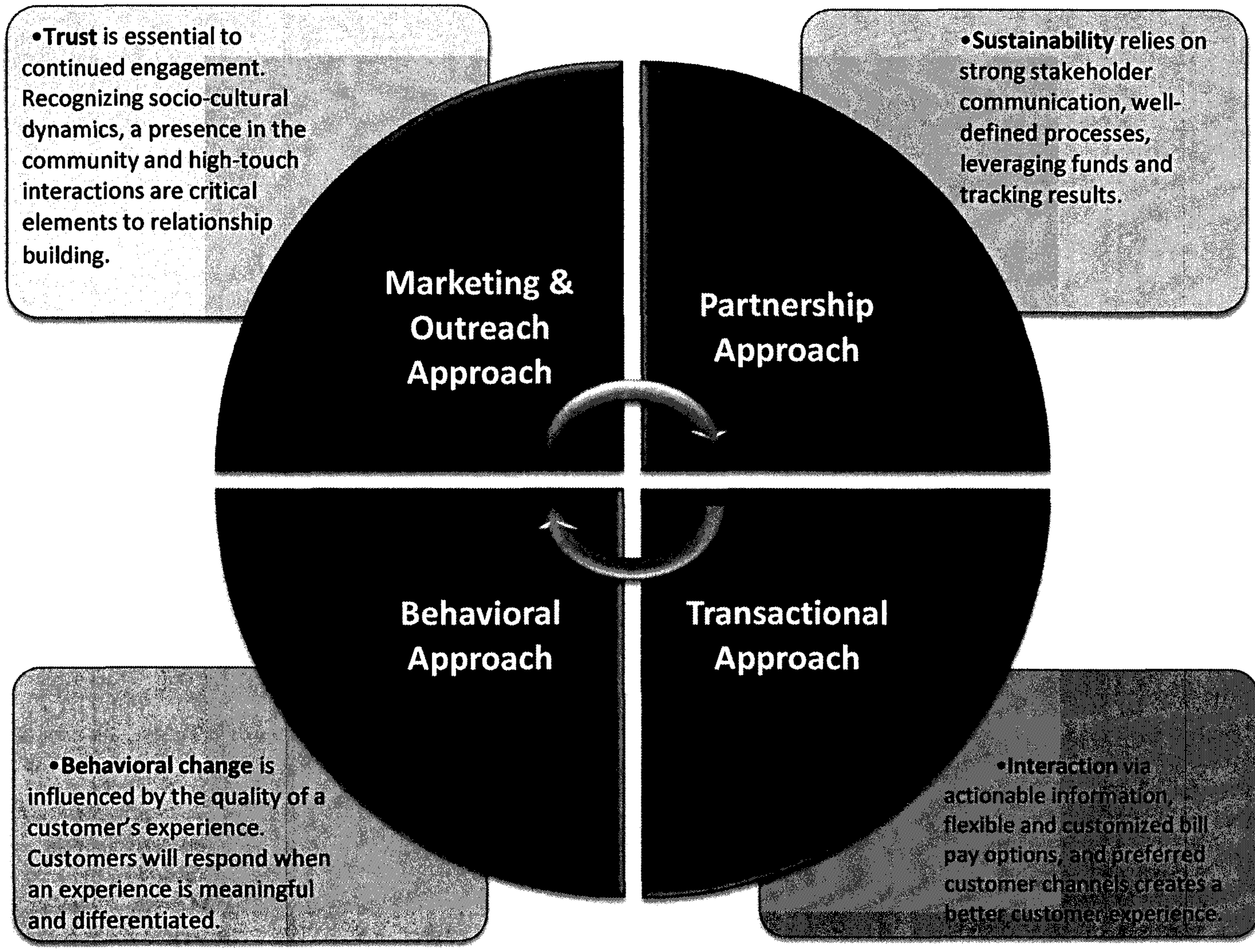
1. *Marketing & Outreach*:
   How do you reach these customers?
   How do you engage in a more personal way to build trust?
   How do you address questions regarding the "split incentive" that exists in the landlord/tenant setting?

2. *Behavioral*:
   What can these customers control?
   What measures deliver value and fit their lifestyle?
   How can the customer experience be differentiated and improved?

3. *Partnerships*:
   Who are the stakeholders that need to be in the communication loop?
   Who are the "right" partners?
   How can funds be leveraged creatively to have the greatest impact for energy providers and customers?

4. Transactional:
   How do you maintain consumer protections while also providing additional flexibility and new payment options that create opportunities for improved cash, credit and energy management?
   What actionable information and payments features customize and improve the customer experience?

The below graphic captures the main themes of the four approaches and highlights their value. These themes should operate as the pillars of a low income energy consumer marketing effort.



While the four approaches work in a complementary manner to fill existing gaps and increase engagement with low income customers, there are many considerations and more work to be done. Through discussions with the Forum participants, knowledge gaps and specific areas for further analysis and improvement were identified.

Below are key points raised by Forum participants:

- There needs to be better internal coordination—employees aware that certain customers have applied for assistance funds should share that information with colleagues working in energy efficiency programs
- Likewise, when a customer meets a percentage of income requirement, typically there is no corresponding energy efficiency piece tied to the program—a more holistic approach needs to be taken
- Better information sharing must also happen with external partners—social service agencies should refer low income consumers to the right person at a utility or retail energy provider to discuss energy efficiency options
- Low income customers are often on the wrong rate or tariff due to an inability of the utility to communicate the benefits of an alternative plan in a meaningful yet simple manner

- Utilities and retail providers are challenged with how to communicate regarding energy usage and efficiency measures—customers cannot repeatedly be told to use less energy—there needs to be a new message
- While certain organizations emphasize customer education and may track bill payment activity before and after DSM project work to ensure that customers are not falling into arrears, no comprehensive metrics are in place—there is a need for evaluation criteria to measure the impact of community-based organizations actions
- Also noted were integration challenges with community-based organizations, third-party providers and channel partners—these relationships are necessary and require resources spent on training and managing content—again, performance metrics would be a sensible measure for ensuring results
- Low income customers are often renters so building characteristics, etc. are beyond their control—this makes it difficult to reach them and share opportunities, thus new strategies and messaging must be developed
- There is a push by utilities to provide more information to customers by leveraging different channels
- Sub-segmenting efforts should be pursued for all consumers, including low income—utilities and retail providers need to better understand trends and communication preferences
- Smart meter create opportunities to leverage more accurate customer usage information, in addition to being able to provide more detailed information about usage directly to the customer
- DSM programs should be customized to meet lifestyles and needs (e.g., multi-generational families, larger families, smaller dwellings, renters)—the offering needs to make sense and offer value to the low income family
- DSM measures should help low income customers better manage costs and offset higher energy prices—this becomes even more critical with assistance levels declining
- Would be valuable to determine utility DSM participation levels and whether funds are being left on the table
- Thought should be given to transitioning a customer assistance model to a self-sufficiency model by combining DSM measures with an actionable, customized bill pay, arrears and energy management platform
- In applicable jurisdictions, retail choice should be considered as a way to save consumers money
- Finally, high-touch interactions are critical to relationship building with low income populations

The ultimate goal is to provide a better low income customer experience that delivers benefits to the consumer and meets regulatory, business and societal goals around energy efficiency and management. The issues are far reaching and can be complex but presented here is a definite line of sight or vision for improved engagement with low income consumers.

About DEFG and the Low Income Energy Issues Forum

Distributed Energy Financial Group LLC (DEFG), a specialized consulting firm focused on energy consumers, manages the Low Income Energy Issues Forum.

Cindy Boland O'Dwyer, a Vice President with DEFG and a lawyer, is the author and contact for the Low Income Energy Issues Forum. Cindy can be reached at: codwyer@defgllc.com.

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A6

Electric Power Supply Association

Myths & Realities of Competitive Electricity Markets

Myth: Electricity restructuring has failed because retail rates are rising - not dropping - in regions with competitive electricity markets.

Reality:

Electricity rates have been rising throughout the country, not only in restructured states. These increases are largely a result of rising costs for the fuel used by generators to produce electricity. In fact, fossil fuel costs have increased over 150 percent since 1999. Fuel costs are rising due to global demand for fossil fuels, the impact of supply interruptions from the hurricanes in 2005, and insufficient domestic production. The push for cleaner, more reliable and efficient power plants drive costs higher as well. Despite this pressure, if one takes into account price increases over the same time-frame in other consumer goods like food, housing and health care, electricity price increases are mostly modest by comparison. In addition, wholesale prices actually declined last year in some regions.

Electricity rates are not rising because of the competition brought about in those states that restructured electricity. Many of the states that introduced retail competition incorporated rate freezes that kept rates unchanged for a period of years even as the input costs for generating electricity increased dramatically. These artificial price freezes are not sustainable in the face of these economic realities, particularly when they have been in effect for many years.

Make no mistake - **retail customers in states that do not allow customer choice have experienced higher rates as well** - often in the form of an automatic increase on their bill. **In these states, steady increases over a number of years have been passed through to consumers**. These regular, smaller price hikes can add up to dramatic changes in price over time. **Recent reports by several state utility commissions document that prices in competitive markets are lower than what would have been the case in a rate-regulated environment had those states not restructured.**

Myth: Rates may be increasing across the country, but the worst increases have been in restructured states.

Reality:

Not so.

In most of the states that restructured to increase competition, political agreements were made to cap rates for a certain period of time and, in some cases, actually roll them back. As a result, many customers in restructured states have been paying below market rates in recent years despite increases in the input costs for generating electricity. As these rate caps expire, rates are catching up and starting to reflect current market prices that are being driven by significantly higher fuel prices. In spite of this, public reports show that even when current prices are adjusted for fuel increases, customers have saved billions of dollars as a result of competitive markets and restructuring. Some state regulatory commissions have taken a variety of steps to phase in these rate increases so customers do not experience a large increase all at once. Finally, **requiring utilities to supply power at below market rates keeps competitors from entering those markets.** By contrast, states without such restrictions, such as New York and Texas, have markets with multiple competitors selling to consumers.

Myth: Advocates of competition promised better prices for consumers and that there would be many companies fighting to supply customers in states that restructured. Those companies have not made the investments to provide customers the choices they were promised.

Reality:

There are, in fact, many competitive suppliers fighting to serve customers, and studies have repeatedly shown that there have been lower costs resulting from competitive reforms. In a number of cases, that competition is occurring at the wholesale level. Electricity distribution companies have more options than ever before. They can run their own plants, or buy from a wide range of power suppliers - a fact that may be unknown to most retail electricity consumers. In Illinois, New Jersey and Maryland, for example, a dozen or more electricity suppliers participated in state-supervised auctions, fighting for the right to help meet consumer power needs.

Many states have successful competitive programs for retail consumers. A small business or farm in Texas, for instance, may choose to buy electricity from any one of a number of quality companies, who can offer a range of products and services (including "green" or "clean" power options). Where the electricity prices were artificially reduced or frozen by regulation, competition generally has not yet fully evolved. These artificially low prices have kept away alternative retail suppliers to the traditional local utility. However, once price freezes end, there is a greater incentive for more competitive suppliers to enter the markets. The rapid switching to alternate suppliers, particularly by commercial and industrial customers, in states that recently lifted rate caps is proof of this point. The same goes for the high retention rate of end-use customers already served by competitive retail suppliers.

Myth: A return to cost-based rate regulation is more practical given competition's failure.

Reality:

States chose to restructure in the 1990s for the very reason that **cost- or rate-based regulation was failing.** The goal of policymakers at the time was to ensure affordable and reliable electricity for consumers. That objective remains today. As it does elsewhere in the economy, **competition keeps costs as low as possible, drives innovation, and produces the benefits customers are seeking.** This is also true for telecommunications services, the advent of discount department stores, or the reforms in the automobile industry in the last quarter century. **The fact is that we need more competition, not less.** Cost-of-service rates encourage power plant operators to inflate costs and run power plants inefficiently, which saddles consumers with over-priced electricity.

Before restructuring, many power plants were running at only a fraction of their capability. There were massive cost overruns on the construction of new power plants - evidence of this exists today in non-restructured regions like the Southeast. There was little incentive for utilities to save money because everything was bankrolled by the captive customer who had no other choice. Many of these captive customers were the businesses - small and large - that create jobs and build the economy.

When electricity suppliers are allowed to compete to sell their product, the customer wins. If a customer could only buy their car - a critical investment for many - from one company, the result would be higher prices, poor - or no - choices, and ultimately, an unhappy customer. **When prices are controlled by regulation and based on whatever costs are deemed "prudently" incurred - plus an administratively determined profit margin - traditional utilities are rewarded for charging more, not less.**

Myth: While we cannot completely "put the genie back in the bottle," we should, at the very least, return to cost-of-service rates for the generation of electricity; after all, it seems to work well in the Southeast.

Reality:

In the Southeast, rates have been historically lower than in some other regions because much of the electricity is generated by very old power plants with relatively modest environmental controls and better access to a range of fuel resources. These factors, not vertically-integrated utilities regulated under "cost-of-service" rates, gave this region an advantage over regions that have tougher environmental requirements and newer power plant investments. Whether this advantage will remain in the future is an open question for the Southeast as the cost of fossil fuels rises, and as the power plants in the region are required to install expensive pollution control equipment to meet tougher federal Clean Air Act regulations.

Even in the Southeast, there is ample evidence that increased competition would provide benefits to consumers. For example, in many Southeast states, highly inefficient and costlier natural gas-fired generation continues to be operated by vertically-integrated utilities, while state-of-the-art units built by competitive suppliers, that could save precious natural gas resources and consumers' money, are idled by poor power procurement policies and discriminatory transmission practices.

Myth: Competitive companies can go bankrupt, yet regulated monopolies seldom do. This proves that competitive companies are poorly equipped to provide the public with electricity, an essential commodity.

Reality:

One of the most important benefits of competitive markets is that they shift investment risks away from captive ratepayers to competitive power suppliers. Competitive companies are more disciplined because more is at risk for them if they fail. For one thing, **competitive power suppliers are not paid unless their power plants generate power or provide capacity, and their plants do not run if their output is not priced to beat their competitors.** By contrast, rate-based utilities are paid regardless of whether their plants run efficiently or run at all. **Rate-based facilities have incentives to drive up rates to earn a profit on those higher costs.**

Competitive suppliers focus on managing all of the risks associated with producing power. Competitive companies that filed reorganized their affairs **continued to operate and supply power to customers, and in almost every case, are now strong financially.** Corporate executives may lose their jobs, but the good news is that the customer wins because suppliers bear the risk. **Those competitive suppliers that have been**

reorganized emerged from bankruptcy as stronger competitors. By contrast, when financial difficulties strike rate-based utilities, captive ratepayers or taxpayers are burdened with the cost. Over the last thirty years, these consumers have paid tens of billions of dollars for utility mistakes. Competition is better for consumers.

Myth: Competition was supposed to shift the risk away from consumers. But now generators want "capacity payments" in addition to what they receive for the power they generate. These payments are just another guaranteed rate of return like the system that competition was supposed to replace. What's worse, now they're saying even capacity payments aren't enough to get them to build new coal and nuclear plants at a time when we need to diversity our fuel sources away from natural gas to generate electricity.

Reality:

In a fully competitive market, power generators would only get paid for the electricity they produce. However, rather than fully embracing competition, every wholesale market today has one or more forms of "market mitigation" - a fancy term for artificial limits on prices regardless of underlying supply and demand. If prices are held artificially low for a period of time, particularly as operating and capital costs for new plants increase, investment in new facilities will not be made, and even existing plants may not be able to be maintained. Therefore, a capacity payment is needed to compensate a power generator for some of the fixed costs of the power plant that stands ready to generate electricity as needed to meet consumer demand. This is especially important for plants that are desperately needed to keep the lights on during the hottest summer or coldest winter days but run less the rest of the year.

Competitive suppliers already operate a diverse mix of coal, nuclear, renewable, and gas-fired power plants. These companies are also developing new coal, nuclear and renewable plants and expanding existing facilities. Whether they are built by a competitive supplier or a vertically integrated monopoly utility, coal and nuclear plants require billions of dollars to construct, take a long time to build, and may not work as predicted when new technologies are deployed. In markets where wholesale prices are artificially limited, capacity payments may be the only way to ensure that needed, fuel-diverse power plants get built - on time and without regulatory guarantees that force customers to pay for bad investment decisions.

Myth: To build new IGCC coal gasification or nuclear power plants built in our state, the best approach would be to help a utility finance this project with state bonds or other ratepayer and taxpayer incentives.

Reality:

Hardly. When the nation relied on utilities to build all the new power plants in a given area 20 years ago, billions of dollars in "stranded costs" were created. It has been proven time and again that competition can get those plants built and operating more quickly and more cost effectively. Competitive suppliers own and operate nuclear, coal, natural gas and renewable power plants. Any state that desires a specific resource mix should decide what type of incentives to offer and then invite all developers to compete to build new plants with those incentives. Just as consumers would comparison-shop before buying a car, anyone seeking a new power plant should recognize that head-to-head competition is the best way to ensure that customers get the best deal and are not burdened with cost overruns or poorly operating plants. The "right plant" should be constructed at the best cost.

Myth: We don't need to build more power plants. The lights are on today, so we should focus on conservation, transmission and the plants that we have today.

Reality:

This is a false choice. Electricity demand is projected to substantially increase over the next decade even with greater conservation. The U.S. economy has become remarkably energy-efficient in recent decades. However, electricity remains the lifeblood of the economy, powering homes, factories, hospitals and the information age. As the economy grows and the population expands, new power plants will be needed to meet these demands and replace aging power plants that use too much fuel and have higher emissions.

Just as financial advisors recommend that consumers diversify their financial assets, we need a diverse mix of new generation plants using a variety of fuels, as well as more conservation, more energy efficiency, and more investment in transmission. We also need greater efficiencies and higher output from existing power plants. Competitive suppliers have proven they can run existing plants better than before competitive markets were introduced. Lastly, competitive markets bring more transparency to retail prices. Often, rate-based regulation leads to hidden costs and confusing bills that hinder effective conservation policies.

Myth: All competition has brought is more natural gas fired power plants, when what the nation needs is more coal and nuclear generation. Competitive markets seem to be permanently biased toward construction of a gas-fired plant.

Reality:

Competitive electricity suppliers are the most fuel diverse generators in the business. Nearly 40% of the electric generation capacity in the U.S. is competitive and more than two-thirds of this output is from coal, nuclear and renewable power plants.

During most of the past 15 years, natural gas has had cost and environmental advantages that made it preferred by new power plant developers - whether in competitive markets or under rate-based regulation in states that did not restructure. When natural gas prices have risen significantly, there has been a steady shift to interest in alternative resources such as coal, renewables, and nuclear energy. Competitive markets have helped this process by creating fundamental new opportunities for investment in fuel diversity. Coal-fired power plants that are built at the mine (mine mouth) can rely on new regional markets to obtain access to distant customers. High technology renewable power developers can implement national strategies appropriate to the resource (e.g., wind). Larger company balance sheets, better nuclear plant management and environmental considerations are opening the door to the first new nuclear investment in a generation. Lastly, competitive generators have an excellent record of true technical innovation. Whether it is gas, coal or renewables, our companies are on the cutting edge when it comes to efficiency, cost-management and better pollution control.

Some natural gas-fired power plants that were built recently are, in fact, not running today - idled by high gas prices. If these unused power plants are owned by rate-regulated utility companies, customers are paying for them anyway. If these plants are owned by competitive firms, the customers are not. Once again, for cost-plus businesses, good investment strategies and ideas are not required. In competitive markets, they are.

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1401 New York Avenue, NW Suite 1230, Washington, DC 20005-2110
phone (202) 628-8200 fax (202) 628-8260

A7

Retail Electric Competition in Michigan:

GROWING MICHIGAN'S ECONOMIC GARDEN

Report prepared for: Energy Choice Now
Prepared by: Continental Economics, Inc.
August 2012

CONTINENTAL ECONOMICS

Executive Summary

The U.S. economy remains sluggish, forcing states to scrutinize their budgets and determine ways to drive economic growth and job creation. Michigan in particular felt the effects of the recession, with unemployment doubling to 14% from 7% in 2008. Although unemployment has dropped, the 8.6% unemployment rate that Michigan now faces is still higher than the national average.

While the path to an economic recovery is still being forged, policies that ensure businesses can access reliable, competitively priced electricity from a wide range of providers at the lowest possible cost factors in to businesses' decisions about whether to stay, move, expand or relocate from one state to another.

Between 2000 and 2008, all Michigan consumers were able to choose their own electric supplier, enjoying significant savings in electricity costs. Additionally, during that period of full electric choice, over 4,000 megawatts of new generating capacity was built by independent developers in Michigan and the state began closing the gap on energy rates with neighboring and competing states.

In October 2008, however, Governor Granholm signed into law legislation promising to significantly decrease electricity rates for Michigan's businesses, but also eliminating almost all retail electric competition by capping it to just 10 percent of total electric use. Proponents of competitive markets warned that a return to the old-style monopoly utility regime would increase rates for everyone, discourage innovation, and deter investment in cost-efficient generation.

Those warnings came true: retail rates charged by the states' two largest electric utilities, Consumers Energy (CE) and Detroit Edison (DTE), have <u>soared</u> since 2008. As shown on Table EX-1, **residential customers** at CE have been hardest hit, **suffering a 47% increase** in their electric rates over the last four years. But business consumers have been hard hit too. Rates for small commercial customers of CE—the "mom-and-pop" businesses which can provide the largest source of employment growth—have increased by **30%.** Large **commercial customers** have fared even worse, absorbing a **40% rate increase**. And, rates for **industrial customers**, the most intensive electric users of all, have **increased by 35%**. However, while CE's and DTE's rates soared, wholesale generation prices in MISO fell by almost half.

Table EX-1: Changes in Retail Electric Rates and Wholesale Prices (2008-2012)*

Utility	Residential	Sm. Commercial	Large Commercial	Industrial	Change in Avg. MISO Wholesale Prices
	[1]	[2]	[3]	[4]	[5]
Consumers Energy	47%	30%	40%	35%	**-44%**
Detroit Edison	28%	20%	13%	18%	**-46%**
Average	**38%**	**25%**	**27%**	**26%**	**-45%**
Average Annual Increases in Cost per Customer					
Consumers Energy	$559	$1,848	$14,213	$1,217,760	
Detroit Edison	$397	$1,296	$6,048	$712,080	
Average	**$478**	**$1,572**	**$10,130**	**$964,920**	

Notes:
* Rates based on comparison as of December 1 each year, and June 1, 2012.
** Cost impacts based on annual consumption
[1] 1,000 kWh per month consumption
[2] 25kW demand and 5,000 kWh per month consumption
[3] 100kW demand and 36,000 kWh per month consumption
[4] 10,000 kW demand and 4.3 million kWh consumption
[5] Based on average of hourly LMPs, Consumers and DTE Hubs

Source: MPSC. http://www.dleg.state.mi.us/mpsc/electric/download/rates1.pdf ; MISO

Today, Michigan has an opportunity to enact legislation that can help improve the state's economy, by allowing more businesses and individuals to shop for their electricity in the competitive market. The key to unleashing the economic potential of lower electricity costs is to focus on long-term benefits and create a steady, certain path towards full retail competition. This requires letting market forces work as they should, rather than trying to manage outcomes with oppressive government command and control.

Legislation that has been introduced by Representative Mike Shirkey, R-Clark Lake (HB 5503) and Senator Arlan Meekhoff, R-West Olive (SB 1035) is a step in the right direction. This legislation would gradually increase the 10% cap on electric competition in Michigan and allow **the more than 9,600 businesses currently languishing on a waiting list** immediate access to competitive generation suppliers. These customers **could save an**

estimated additional $170 million per year on electric costs,[1] money that could be reinvested to grow Michigan's businesses and economy.

[1] The $170 million annual value is based on the total reported annual MWh in the queue for CE and DTE as of June 30, 2012, times the difference between an estimated average retail price of $55/MWh and an average generation price of $75/MWh. With a total of 8,456,119 MWh in the queue and average savings of $20/MWh, this results in annual savings of $170 million.

I. Introduction

As the U.S. economy continues to struggle, states are looking for ways to promote economic growth and job development. Michigan was particularly hard hit by the recession with unemployment doubling from 7% in 2008 to 14% just one year later. While the state's unemployment rate has dropped since then, 8.6% is still above the national average.[2]

Although there is no magic bullet to restore economic vitality overnight, proven policies exist to increase innovation and investment by local businesses, thus spurring economic growth and job creation.[3] The most familiar policies are stable and low tax rates and eliminating needless government regulations that bury businesses in red tape. Less familiar, but just as important, are policies ensuring businesses can access reliable, competitively priced energy supplies from a wide range of providers—including electricity—at the lowest possible costs. Michigan's electricity rates are above the national average, and the highest in the Midwest.

Michigan's electricity rates are above the national average, and the highest in the Midwest.

Michigan faces a critical economic decision. Many in the state want to fully embrace electric competition to improve the economic climate, spur innovation, and reduce Michigan's electricity rates to be competitive with its neighbors, including Illinois and Ohio.

Others, however, wish to return to the past, eliminating electric competition entirely. They want the state's monopoly utilities to completely control what resources are built and to force their customers to bear all of the resulting financial risks, while continuing to reimburse the utilities for stranded costs. Ultimately, this choice boils down to a vision for the Michigan economy: a well-tended, thriving garden, or a weedy patch that businesses and consumers flee.

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2 Source: U.S. Bureau of Labor Statistics. Data for June 2012.

3 *See, e.g.*, "Electricity Competition at Work: The Link Between Competitive Electricity Markets, Job Creation, and Economic Growth," Continental Economics, Report prepared for the COMPETE Coalition, September 2011. http://www.competecoalition.com/files/COMPETE%20Electricity%20Competition%209.22.11.pdf

II. Electric Restructuring in Michigan – A Brief History

To counteract the job-killing impacts of higher energy costs in the late 1990s, Governor John Engler initiated the restructuring of Michigan's electricity market to create competition and the legislature passed the "Customer Choice and Electric Reliability Act" of 2000. In exchange for making certain regulated generation assets competitive, Michigan's two largest utilities, DTE and CE, collectively received from ratepayers $163 million in "stranded" costs and also were permitted to "securitize" other generating assets through a 15-year bond issue in the amount of $2.2 billion.[4] Of course, utilities continued to be compensated for their distribution (i.e., "poles and wires" service), because it would make no economic sense to have competing firms stringing electric wires. Thus, distribution remains fully regulated, to ensure that electricity is delivered properly to all customers.

Between 2000 and 2008, all Michigan consumers were able to choose their own electric supplier, which resulted in significant savings in electricity costs. During that period of full electric choice, over 4,000 megawatts of new generating capacity was built by independent developers in Michigan, just as those developers built thousands of MW of generation in other states with electric competition. The state began reducing the gap between retail electric rates with neighboring and competing states, and rates fell below the national average. Retail competition did not cause electric rates for customers who remained with the utilities to skyrocket. Rather, the competitive market acted to temper rate increases and brought those rates in line with other Midwest states.

4 "Stranded costs" are the difference between the net book value of generating assets and their value in the competitive market. As an analogy, a home with a market value of $200,000, but an outstanding mortgage of $250,000, has $50,000 of "stranded cost." The definition of stranded costs under Michigan law can be found at 2000 P.A. 141, Michigan Compiled Laws 460.10a(10). Securitization essentially allowed the utilities to refinance above-market stranded costs using low interest rate debt.

Competition Ends—Electric Consumers' Stranded Cost Obligations Continue

In October 2008, however, Governor Jennifer Granholm signed legislation into law[5] promising to significantly decrease electricity rates for Michigan's businesses, but also eliminating almost all retail electric competition by restricting it to just 10% of total electric use. DTE and CE heavily supported this legislation, claiming they needed a captive customer base to finance new, expensive power plants to meet future electric demand and replace an aging generation fleet. Moreover, the new legislation continued to allow these utilities to recover stranded generation costs, even though the initial regulatory "bargain"—stranded cost recovery in exchange for retail competition—was now broken. Thus, the state's electric utilities continue to be compensated by customers for their above-market costs, while the vast majority of these same customers are now denied the benefits of competition.

Proponents of competitive markets warned that a return to the old-style monopoly utility regime would increase rates for everyone, discourage innovation, and deter investment in cost-efficient generation. In fact, academic studies have found that generation plants in fully competitive markets have improved their operating efficiency, and lowered costs, far more than their regulated counterparts. For example, a 2004 Massachusetts Institute of Technology (MIT) study concluded that investor-owned utility plants in states with fully restructured electricity markets reduced operating expenses far more than their still-regulated counterparts.[6] In 2006, MIT Professor Paul Joskow, who has studied electricity markets for three decades, wrote, "well-designed competitive market reforms have led to performance improvements in a number of dimensions and benefited customers through lower retail prices."[7] He further noted:

5 H.B. 5524, P.A. 286 (2008).

6 Rose, N., K. Markiewicz, and C. Wolfram, "Does Competition Reduce Costs? Assessing the Impact of Regulatory Restructuring on U.S. Electric Generation Efficiency," Massachusetts Institute of Technology, Center for Energy and Environmental Policy Research, 04-418 WP, November 2004. http://web.mit.edu/ceepr/www/2004-018.pdf

7 Joskow, P., "Markets for Power in the United States: An Interim Assessment," *The Energy Journal* 27 (January 2006), pp. 1-36. http://econ-www.mit.edu/faculty/download_pdf.php?id=1219

> [t]he revisionist history about the "good old days of regulation" has conveniently ignored the $5000/kW nuclear power plants, the 12 cent/kWh PURPA contracts, the wide variations across utilities in the construction costs and performance of their fossil plants, and the cross-subsidies buried in regulated tariffs that characterized the regulatory regimes in many states. As we look at the costs and benefits of competition we should not forget the many costly problems that arose under regulation.[8]

Most significantly, in the four years since the 2008 energy law was passed, CE and DTE have greatly <u>increased</u> their rates. Michigan's electricity market performance proves the state should have heeded the earlier warnings.

By the end of 2009, only one year after the new legislation took effect, the 10% cap was hit. Residential customers now pay hundreds of dollars more each year for electricity, while commercial and industrial customers pay thousands more. Yet, over these same four years wholesale electricity prices have fallen by almost half. We estimate that businesses fortunate enough to have made it under the cap have saved over $350 million in electricity costs in those three years.[9] But over 9,600 businesses are stuck on a waiting list hoping for an opportunity to shop to escape the escalating monopoly rates charged by CE and DTE. We estimate these customers could save an additional $170 million per year on electric costs,[10] money that could be reinvested to grow Michigan's businesses and economy.

Residential customers now pay hundreds of dollars more each year for electricity, while commercial and industrial customers pay thousands more. Yet, over these same four years wholesale electricity prices have fallen by almost half.

Because of electricity's fundamental role in our economy, electricity prices have a direct impact on economic growth, as well as job retention and creation. Just as the effects of high oil and gasoline prices ripple through the U.S. economy and destroy jobs, so do high

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8 *Id.*, p. 33.

9 The $350 million estimate is based on shopping MWh for the period 7/2009 – 6/2012, times the difference between the average competitive retail market price (wholesale price plus $10/MWh mark-up) and the average of CE's and DTE's published generation rates each year.

10 The $170 million annual value is based on the total reported annual MWh in the queue for CE and DTE as of June 30, 2012, times the difference between an estimated average retail price of $55/MWh and an average generation price of $75/MWh. With a total of 8,456,119 MWh in the queue and average savings of $20/MWh, this results in annual savings of $170 million.

electricity prices. As the Rhode Island Public Utilities Commission said in a 2010 decision disapproving an expensive contract:

> It is basic economics to know that the more money a business spends on energy, whether it is renewable or fossil based, the less Rhode Island businesses can spend or invest, and the more likely existing jobs will be lost to pay for these higher costs.[11]

Competitively priced electricity and innovative products are critical to the success of businesses, searching for new ways to reduce costs and improve efficiency. High electricity prices deter business expansion and job creation, and force businesses to seek out states providing more favorable economic climates. According to a recent report by Deloitte, 85% of all businesses view reducing their electricity costs as essential to remaining competitive.[12] This is especially true in a state like Michigan, with its heavy manufacturing presence.

III. Dollars and Cents: How do Electric Prices in Michigan Compare?

Michigan Retail Electric Rates – Up, Up, and Away

As mentioned previously, since 2008, retail rates charged by CE and DTE have soared, with both companies having increased their rates each year since. As shown on Table 1, residential customers at CE have been hardest hit, suffering a 47% increase in their electric rates over the last four years. But businesses have also been hard hit. Rates for small commercial customers of CE—the "mom-and-pop" businesses which can provide the largest source of employment growth—have increased by 30%. Large commercial customers have fared even worse, absorbing a 40% rate increase. And, rates for industrial customers, the most intensive electric users of all, have increased by 35%.

The rate increases since 2008 for DTE's customers, although somewhat smaller, have still been substantial. Their residential customers' rates increased 28% and small commercial

[11] *In Re: Review of New Shoreham Project Pursuant to R.I. Gen Laws § 39-26.1-7*, Docket No. 4111, Report and Order, April 2, 2010, p. 82. Subsequent to rejecting the proposed contract, the Rhode Island legislature passed a law that, in essence, mandated the Rhode Island PUC to approve the contract.

[12] Deloitte Center for Energy Solutions, 2012 reSources Study. http://www.deloitte.com/view/en_US/us/Industries/oil-gas/Deloitte-Center-for-Energy-Solutions/8e3262fa8b1ae210VgnVCM1000001a56f00aRCRD.htm#

customers increased 20%. Larger commercial and industrial customers have also suffered double-digit increases of 13% and 18%, respectively.

Table 1: Changes in Retail Electric Rates and Wholesale Prices (2008-2012)*

Utility	Residential	Sm. Commercial	Large Commercial	Industrial	Change in Avg. MISO Wholesale Prices
	[1]	[2]	[3]	[4]	[5]
Consumers Energy	47%	30%	40%	35%	**-44%**
Detroit Edison	28%	20%	13%	18%	**-46%**
Average	**38%**	**25%**	**27%**	**26%**	**-45%**
<u>Average Annual Increases in Cost per Customer</u>					
Consumers Energy	$559	$1,848	$14,213	$1,217,760	
Detroit Edison	$397	$1,296	$6,048	$712,080	
Average	**$478**	**$1,572**	**$10,130**	**$964,920**	

Notes:
* Rates based on comparison as of December 1 each year, and June 1, 2012.
** Cost impacts based on annual consumption
[1] 1,000 kWh per month consumption
[2] 25kW demand and 5,000 kWh per month consumption
[3] 100kW demand and 36,000 kWh per month consumption
[4] 10,000 kW demand and 4.3 million kWh consumption
[5] Based on average of hourly LMPs, Consumers and DTE Hubs

Source: MPSC. http://www.dleg.state.mi.us/mpsc/electric/download/rates1.pdf ; MISO

As Table 1 shows, since 2008 while CE's and DTE's rates soared, wholesale generation prices in MISO fell by almost half.[13] As a recent report issued by the COMPETE Coalition states,

> Most significantly, competitive retail electric markets enable consumers to benefit from lower wholesale prices. In contrast, customers in monopoly-regulated markets do not, and cannot, see these price signals. Indeed, an inescapable paradox in

[13] The difference between the average wholesale price decreases for CE and DTE arise because MISO uses locational marginal prices, which provide a market-clearing price at every individual generator interconnection.

monopoly utility regulation is that when supply exceeds demand (and other factors are held constant), prices do not decline, but must increase to cover fixed costs.[14]

This situation aptly describes what has happened in Michigan since 2008: while wholesale market prices have fallen, captive Michigan utility customers have been forced to pay far more for their electricity because of investments in an aging fleet of inefficient generation. Moreover, the regulated retail electric rates paid by Michigan customers in 2011 were significantly higher than in neighboring Midwest state, as shown in Table 2. For industrial customers, the average rate difference was over 18% and the difference between the average industrial rate in Indiana and that in Michigan was 65%. For firms operating in highly competitive markets, these rate differences can have a huge impact on the "bottom line."

Table 2: Comparison of Average Electric Rates by Sector, 2011

Sector	Illinois	Indiana	Ohio	Wisconsin	Average	Michigan	Difference (%)
	Cents/kWh						
Residential	11.81	10.06	11.44	13.06	**11.59**	13.12	**13.2%**
Commercial	8.64	8.74	9.60	10.43	**9.35**	10.32	**10.3%**
Industrial	8.64	6.25	9.60	10.43	**8.73**	10.32	**18.2%**

Source: U.S. EIA, Electric Power Monthly

The tremendous savings realized by the approximately 7,000 customers under the cap fortunate enough to have choice are directly tied to these lower wholesale market prices. Thus, while these few lucky customers benefit from lower wholesale prices, millions of other customers denied choice have been forced to pay far higher prices, even though CE and DTE themselves purchase electricity from the wholesale market at much lower prices. In a cruel irony, House Bill 5733, which was introduced on June 13, 2012, would effectively eliminate choice for even the 10% of load forcing them to pay far more for their electricity.

[14] P. O'Connor, "Retail Electric Choice: Proven, Growing, Sustainable," Report prepared for the COMPETE Coalition, April 2012 (footnote omitted). http://www.competecoalition.com/files/COMPETE_Coalition_2012_Report.pdf

In Illinois, Ohio, and Pennsylvania, nearby states that compete with Michigan businesses, retail electric choice is both popular and effective. Table 3 provides a summary of retail competition statistics in Illinois, Ohio, Pennsylvania, and Michigan.

Table 3: Retail Competition Statistics, 2011

Customer Class	State			
	[1]	[2]	[3]	[4]
Non-Residential	**Illinois**	**Ohio**	**Pennsylvania**	**Michigan**
Pct. of Load	82.6%	57.2%	78.8%	11.0%
Pct. of Customers	31.2%	42.2%	41.4%	1.6%

Customer Class	State			
Residential	**Illinois**	**Ohio**	**Pennsylvania**	**Michigan**
Pct. of Load	10.9%	32.4%	29.9%	0.0%
Pct. of Customers	10.1%	35.1%	29.4%	0.0%

Notes:

[1] Source: Illinois Commerce Commission, Electric Switching Statistics, April 30, 2012. http://www.icc.illinois.gov/electricity/switchingstatistics.aspx

[2] Source: Ohio Public Utilities Commission, "Summary of Electric Customer Choice Switch Rates," Q4 2011, http://www.puco.ohio.gov/puco/index.cfm/industry-information/statistical-reports/electric-customer-choice-switch-rates/

[3] Source: Pennsylvania Public Utilities Commission. "Weekly PAPower Switch Update," June 20, 2012. http://extranet.papowerswitch.com/stats/PAPowerSwitch-Stats.pdf?/download/PAPowerSwitch-Stats.pdf

[4] Source: DNV KEMA, Retail Energy Outlook Q1 2012.

As Table 3 shows, at the end of 2011, approximately 80% of non-residential loads in Illinois and Pennsylvania were served by competitive electric suppliers. In Ohio, 57% of non-residential load was served by competitive suppliers. (The lower percentage in Ohio stems from limited competition in AEP Ohio's service territory.)

Although somewhat lower, the residential shopping numbers continue to grow. In Ohio, over one-third of all residential customers purchase electricity from competitive retail suppliers.[15] In Pennsylvania, rate caps across the state only expired in 2010, but already over 30% of residential customers statewide shop. In Illinois, residential shopping only began in earnest in 2011, when new pro-competitive policies were implemented, and 10% of residential customers already have switched. That percentage is expected to increase rapidly as municipalities embrace competitive electricity prices through municipal aggregation programs. These three states are merely examples of the growth in electric shopping that is taking hold in all competitive states across the nation. Since 2008, customer accounts served under retail electric choice have grown by over 53% and total electric load served competitively has increased by 40%.[16]

"Competitive markets are absolutely essential for driving innovation, in any industry, and innovation is absolutely essential to drive down costs, provide consumers products they need, and grow business. Two of Dow Corning's Michigan facilities have been able to access the competitive electricity retail choice market and reduce our electricity cost by approximately 30% at those facilities compared to the utility standard tariff rate."

- Rod Williamson, Energy Development Manager, Dow Corning Corporation

In Michigan, by contrast, the flawed 2008 energy law denying choice to 90% of the load holds retail customers captive to higher utility prices. Thousands of customers remain on the competition waiting list, and no residential customers currently receive their electricity from competitive retail suppliers. In fact, DTE Energy Trading, the competitive retail subsidiary of DTE, won several competitive auctions to provide "default service" electricity to customers in Ohio. The price of that competitively provided default service in one Ohio territory was as low as 4.5 cents/kWh, as opposed to the 6.9 cents/kWh that DTE charges its Michigan residential customers under monopoly regulation.[17] Thus, while its corporate parent opposes competition, to the detriment of retail customers in Michigan, DTE Energy

[15] This number is also skewed by AEP Ohio, for which only about 1% of residential customers shopped for electricity in 2011. In contrast, 75% of Cleveland Electric's retail customers shopped for electricity in 2011.

[16] P. O'Connor, "Retail Electric Choice: Proven, Growing, Sustainable," p.3.

[17] This is the standard residential electric service rate for the first 17 kWh/day. Additional consumption is billed at a rate of 8.3 cents/kWh. This does not include delivery charges of 5 cents/kWh. http://www.dteenergy.com/residentialCustomers/billingPayment/electricRate/calculator.html. DTE Energy Trading has also won default service auctions in Illinois, New Jersey, and Pennsylvania.

Trading embraces competitive markets in other states to the benefit of DTE shareholders and retail customers that compete directly with Michigan businesses.

Real Costs – Real Economic Pain – Real Job Losses

As Table 1 shows, rate increases over the last four years have imposed real costs on consumers. A CE residential ratepayer with an average 1,000 kWh electric usage per month, for example, will pay $560 more for electricity this year than in 2008. A DTE residential customer will pay about $400 more this year. A CE small business customer consuming an average 5,000 kWh per month will pay over $1,800 more this year, while a small business customer of DTE will pay $1,300 more. A typical industrial customer of CE, who likely faces intense global competition, will pay over $1.2 million more for its electricity today than in 2008. A typical DTE industrial customer will pay over $700,000 more. In contrast, that customer could save almost $1.5 million with a competitive supplier, based on the large decreases in wholesale electric market prices.

More money spent on electricity means residential consumers have less money to spend on other goods and services offered by local Michigan businesses for food, clothing, gasoline, entertainment, and so forth. This means that those businesses will have less money available to invest and grow, and fewer new employment opportunities. Not only do they pay more for electricity, but they take in fewer dollars from their customers. In contrast, lower electric prices provide consumers and businesses with more money to spend and invest, providing expanded opportunities for growth and jobs. An April 2012 study about the automobile industry, for example, stated that "future industry employment hinges on automakers' ability to not only produce vehicles consumers want to drive, but also solve some internal cost concerns."[18] Michigan's "Big Three" automobile manufacturers likely focus on wages, pension benefits, and health care costs, which are set nationally. Thus, reducing day-to-day operating costs—including the cost of electricity—is another important strategy to improve overall competitiveness and is one of the largest cost differentiators among the different states. By reducing their costs, the Big Three can more

[18] A. Donova, "Automotive Industry Job Summary and Outlook," IBISWorld, Special Report, April 2012, p. 3. http://www.ibisworld.com/mediacenter/pdf.aspx?file=Automotive+Industry.pdf

In all restructured industries, market competition has led to innovation, improved efficiency, and lower prices.

easily expand production and employment. In all restructured industries, market competition has led to innovation, improved efficiency, and lower prices.

IV. Market Competition Works

For example, before telecommunications competition, phone service was limited to "plain old telephone service." AT&T, which supplied the nation's local and long-distance service, was a vertically integrated company. AT&T's technological innovations basically consisted of the Princess™ phone in 1959 ("It's little ... It's lovely ... It lights") and touch-tone dialing in 1963. Prices, meanwhile, were high. After the break-up of AT&T, the "supply" of telecommunications services exploded on multiple fronts and prices plummeted. In 1993, the average cost of a long-distance call to Great Britain was $0.87 per minute. By 2003, the average cost had fallen to just $0.18 cents per minute. Today, using the Internet, one can call anywhere in the world at essentially zero cost.

Similarly, competition in the airline industry, a luxury enjoyed by relatively few, made air travel available to everyone. New airlines offering innovative services, such as Southwest, grew rapidly. Competition created an incentive to improve fuel and operating efficiency. Boeing's new 787 Dreamliner®, for example, is 20% more efficient than its similarly sized competitors, and far more fuel efficient than the company's 1960s-vintage jets.

Natural Gas – From Shortage to Surplus

The natural gas industry provides one of the clearest examples of how competition and restructuring can unleash tremendous benefits. Thanks to low natural gas prices, which have been made possible by the rapid expansion of shale gas supplies and significant technological advances improving gas-fired generator efficiency, natural gas has become the fuel of choice for electric generation accounting for about 25% of U.S. electricity supplies.[19]

The plentitude of natural gas supplies today contrast with the conventional wisdom in the late 1960s that U.S. natural gas supplies would be exhausted within a decade. Wellhead natural gas prices were regulated and capped. Supplies began to diminish as production from existing wells declined. Growth in the natural gas industry came to a standstill because there was little economic incentive to undertake new, more costly exploration. By 1967, estimated reserves had peaked and production began to fall steadily. Shortages began to develop, natural gas service was curtailed for industrial customers, and predictions that "the spigot would run dry" within a decade became prevalent. The situation became so extreme that, in 1978, Congress passed the Powerplant and Industrial Fuel Use Act, which banned the construction of new natural gas-fired generating plants and, instead, urged utilities to build new coal-fired power plants.

> **"Michigan retailers are particularly hard hit by rising electricity costs in this highly competitive marketplace. Retailers need marketplace prices and innovative tools to help manage their energy use -- needs best met through competition and choice."**
> **– James P. Hallan, President and Chief Executive Officer, Michigan Retailers Association**

What changed between yesteryear's dire predictions of the end of natural gas supplies and today's ample supplies and low prices? In a word: competition. Congress removed the artificial price controls that had crushed incentives for natural gas exploration and development. Once these price controls were lifted, market competition worked wonders. Coupled with severing the connection between production, pipeline transportation, and local distribution, by the early 1990s the natural gas market was vibrant. Those dire predictions of shortages had turned into a gas "bubble." The decline in proven reserves slowed and then, amazingly, reserves began to increase rapidly and, by 2009, proven reserves were almost the same as they had been in 1970, four decades earlier.

[19] Source: U.S. Energy Information Administration, Electric Power Monthly, March 2012.

Without vibrant market competition in the domestic natural gas market, the shale gas revolution would never have occurred, and the resulting economic growth and new jobs that shale gas development has spurred in numerous states would not exist. For example, the Pennsylvania Department of Labor and Industry estimates that Pennsylvania employed 200,000 people in jobs related to Marcellus Shale production at the end of 2010.[20] Similarly, a study prepared for the Fort Worth Chamber of Commerce estimated that over 100,000 people were employed in jobs related to the Barnett Shale in central Texas in 2008.[21] A study by Continental Economics estimated that, in 2010, shale gas production had lowered the average U.S. wellhead price of natural by $2.50/Mcf.[22]

Michigan itself has a growing shale gas industry, which is providing a significant boost to the state's economy.[23] The Antrim Shale, which covers most of Michigan and extends into Ohio and Indiana, is a highly productive shale gas source. In 2011, an average of almost 10,000 gas wells produced over 110 Billion cubic feet of natural gas.[24] According to an I.H.S. Global Insight study, in 2010, shale gas development supported more than 600,000 jobs in the U.S., and 28,000 jobs in Michigan.[25] And with three major shale plays in Michigan,[26] that number is expected to grow to more than 63,000 by 2035, based on estimates of future shale gas production levels.

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20 Pennsylvania Dept. of Labor and Industry, *Marcellus Shale Fast Facts*, June 2011. Available at: http://www.paworkstats.state.pa.us/admin/gsipub/htmlarea/uploads/Marcellus_Shale_Fast_Facts_Viewing.pdf.

21 The Perryman Group, "An Enduring Resource: A Perspective on the Past, Present, and Future Contribution of the Barnett Shale to the Economy of Fort Worth and the Surrounding Area," March 2009. Available at: www.barnettshaleexpo.com/docs/2009_eco_report.pdf.

22 "The Economic Impacts of U.S. Shale Gas Production on Ohio Consumers," Continental Economics Report prepared for the Industrial Energy Users – Ohio, January 2012. http://www.continentalecon.com/publications/cebp/ShaleGas2012

23 *See* Michigan House of Representatives Subcommittee on Natural Gas, Report on Energy and Job Creation, "Natural Gas: Improving Michigan's Economy,," pp. 2-9.

24 Source, Michigan Public Service Commission, Antrim Annual Gas Production Summary 2011. http://www.dleg.state.mi.us/mpsc/gas/production/2011sum.pdf

25 IHS/Global Insight, "The Economic and Employment Contributions of Shale Gas in the United States," December 2011. http://www.anga.us/media/235626/shale-gas-economic-impact-dec-2011.pdf

26 In addition to the Antrim Shale, Michigan has the Niagaran Shale and, most recently discovered, the Collingwood-Utica Shale.

The rapid increase in shale gas production, not only promotes economic growth in states like Michigan, Pennsylvania and Texas, but also provides economic benefits throughout the country. Lower natural gas prices benefit industry and consumers. As the electric industry increasingly relies on natural gas-fired generation to meet growing demand, lower natural gas prices have, in turn, reduced wholesale and retail electric prices, again benefitting industry and consumers. For example, a recent study by the author of this report found that, for every $100 million dollar reduction in electric costs, the state of Ohio would create over 1,200 new jobs. Moreover, whether in the natural gas production or generation development industry, competition shifts investment risks from consumers to developers where they belong.

Wholesale Electric Competition – A Remarkable Success

Twenty years ago, Congress passed the Energy Policy Act of 1992, creating a path for competitive wholesale electric markets. These markets have been a remarkable success and, as a result, today Michigan's electric utilities participate in PJM and MISO, the two largest competitive wholesale electric markets in the US. By providing access to thousands of generating plants, PJM and MISO have improved the reliability of the electric system and lowered costs for restructured states. In fact, the very reason for the development of multi-state power pools was to allow electric utilities to coordinate operations and provide reliable service at a lower cost than if they operated on a "go-it-alone" basis. Moreover, wholesale markets like PJM and MISO have created new economic opportunities for renewable energy development, by providing renewable developers with greater access to markets for green energy. States that have restructured their own electricity market to promote retail competition are best able to realize the benefits provided by organized wholesale markets. The reason is retail competition allows consumers direct access to competitive wholesale markets (through competitive retail suppliers) rather than, as in Michigan, being

Retail competition allows consumers direct access to competitive wholesale markets (through competitive retail suppliers) rather than, as in Michigan, being forced to rely solely on the local monopoly utility's resource decisions and having to pay for uncompetitive aging generation plants.

forced to rely solely on the local monopoly utility's resource decisions and having to pay for uncompetitive aging generation plants.

Full Retail Electric Competition: The Logical Next Step

The success of wholesale electric competition made retail electric competition the next logical step in restructuring the electric industry. As shown previously in Table 2, in Ohio, Illinois, and Pennsylvania, retail electric competition has grown rapidly. It has unleashed new and innovative products for consumers, especially business consumers who face intense competition, and allowed the states to fully realize the benefits wholesale competitive markets provide.

The success of competition in the natural gas industry provides a blueprint for the electric industry. Full electric competition will provide industry and consumers with the lowest possible cost electricity, and help grow the Michigan economy. Unlike monopoly electric utilities, competitive wholesale generators have strong economic incentives to increase their efficiency and reduce costs.

Robust retail competition, coupled with already vibrant competitive wholesale markets, provides the incentive for increased efficiency and lower operating costs, innovative new products, and lower retail prices. Today, thousands of businesses benefit from the lower prices and innovation that retail electric competition provides, as do millions of residential consumers. There is no reason that Michigan businesses and consumers cannot do the same.

V. A Path Forward for Michigan

Despite its documented benefits, resistance to retail electric competition remains strong. The state's artificial restrictions on retail electric competition, and the desire by some to eliminate even the small competitive market, will continue to stifle innovation and keep retail electric rates high.

The key to unleashing the economic potential of lower electric costs is to focus on long-term benefits, and create a steady, certain path towards full retail competition. True progress does not mean punishing Michigan's electric utilities to benefit consumers and businesses, because competition is not a zero-sum game. When utilities like CE and DTE are given greater flexibility, they, too, can benefit from competitive markets.

Today, the fact that Michigan customers are waiting for the opportunity to purchase electricity from competitive retail suppliers is evidence of the value of competition and competitive markets. Embracing competition will lower electric costs for all Michigan consumers. Those lower costs, in turn, will stimulate economic growth and create thousands of new jobs for Michigan residents. It will help grow Michigan's economy and position it to better compete with its neighbors.

HB 5503 and SB 1035, which would allow all customers currently on the waiting list to gain immediate access to competitive generation suppliers and gradually raise the cap on retail competition, are a step in the right direction to full retail competition.

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RETAIL ELECTRIC CHOICE:
PROVEN, GROWING, SUSTAINABLE

Philip R. O'Connor, Ph.D.

Prepared for the COMPETE COALITION

April 3, 2012

RETAIL ELECTRIC CHOICE:
PROVEN, GROWING, SUSTAINABLE

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ELECTRIC CHOICE HAS SURGED DURING THE ECONOMIC SLOWDOWN

Electric consumption in the United States was no greater in 2011 than it was in 2008 at the start of the economic slowdown. Yet, since 2008 retail electric choice volumes have surged. Not only has there been substantial growth in customer migration from traditional monopoly-regulated electric supply to market-priced energy, key indicators demonstrate electric choice growth is sustainable.

- Since 2008, customer accounts served under retail electric choice have grown by over 53%, from nearly 8.7 million to more than 13.3 million in 2011.
- Between 2008 and 2011, total electric load served competitively has grown by 40%, or nearly 200 million megawatt-hours (MWh), from about 488 million MWh to 685 million MWh.
- By the end of 2011, retail electric choice supplied more than 18% of the nation's electric load or about one out of every five kilowatt-hours (kWh) in America – even though retail electric choice is largely confined to 18 jurisdictions accounting for about 44% of total United States electric load.[1]

This paper updates a 2010 report by the COMPETE Coalition entitled *Customer Choice in Electricity Markets: From Novel to Normal.*[2]

That 2010 report reviewed the development of retail electric choice from 2003 through the first half of 2010. During that period retail electric choice evolved from an experiment with many doubters to a durable, proven feature of the electric industry.

This 2012 updated analysis depicts a vibrant retail electric choice market, focusing on

- the strong performance of retail choice during a period of serious economic stress;
- the reasons why retail choice has proven to be a sustainable construct that can continue to provide consumers real value;
- the core market features that are critical to supporting the expansion of choice to other states; and
- what is likely to follow this huge expansion of retail choice.

As with the original 2010 report, this update relies substantially on data from the global consulting and information firm, KEMA, the U.S. Energy Information Administration (EIA) and the Annual Baseline Assessment of Choice in Canada and United States (ABACCUS) report produced by the Distributed Energy Financial Group.[3]

PERFORMANCE AND PROSPECTS

Through retail electric choice, millions of residential, business and governmental electricity customers have benefitted from reasonably priced electricity, innovative products and services, greater flexibility and opportunities to capture efficiencies.

State policy makers and utility regulators have removed several legacy obstacles to retail electric choice such as rate caps, poorly designed delivery rates and lack of access to utility billing services for small customers. Regulators have achieved greater consistency in competitive market rules across different utilities within their states. Based on shared experience and learning, the states also have harmonized rules with one another, facilitating even more cost efficient customer service by multi-state competitive energy suppliers. Notably as well, most utilities in electric choice jurisdictions accommodate and support customer choice. For example, the increased focus of utilities and regulators on emerging innovative technologies such as "smart meters" will promote customer choice alongside energy efficiency.

The surge in retail electric choice has not been uniform, however. In several states, most notably California, Michigan, Montana and Oregon, while some customers have access to choice, the rules still prevent most customers from exercising choice.[4] These customers, therefore, cannot access the lower prices and greater contractual flexibility that characterize retail electric choice. California is moving cautiously in the direction of gradually reopening customer choice.[5] Since 2009, it has allowed relatively small amounts of commercial and industrial load to switch to competitive suppliers. Notably, during the four limited enrollments conducted to date, "the amount of space available was reached essentially instantaneously".[6] Recently, Arizona has taken steps to open the door a bit for competitive supply arrangements for large customers up to a total cap of 200 MW.[7] In contrast, Nevada and Virginia have not yet reversed the suspension of customer choice implemented a number of years ago.[8]

While some resistance remains to customer choice, opponents of retail electric choice now rarely argue for rolling back choice in the 18 competitive jurisdictions, as any such efforts would be strongly opposed by the many satisfied shopping customers. Nor can critics argue that service levels and reliability will degrade under choice as experience has proven otherwise. Another demonstrated benefit of retail electric choice is that while millions of customers of monopoly-regulated utilities must pay rates based on legacy cost structures, customers in jurisdictions with retail electric choice can rapidly avail themselves of falling wholesale electric prices which reflect reduced demand and dramatically increased supplies of low cost natural gas, among other factors.[9]

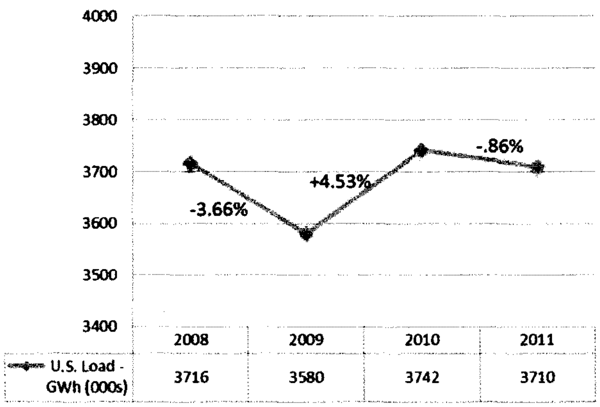
The surge in retail electric choice and the underlying reasons for that surge warrant renewed consideration of providing access to captive customers everywhere. As competitive choice models evolve, they can serve as a basis for a transition to choice in new states seeking favorable opportunities and increased benefits for their consumers.

THE ACID TEST FOR ELECTRICITY CHOICE

The acid test for any business or industry is not only whether its customers buy and like the service or product, but also how well it performs during a period of general economic stress. In the midst of the most significant downturn in the U.S. economy since the Great Depression, retail electric choice is passing that test with flying colors.

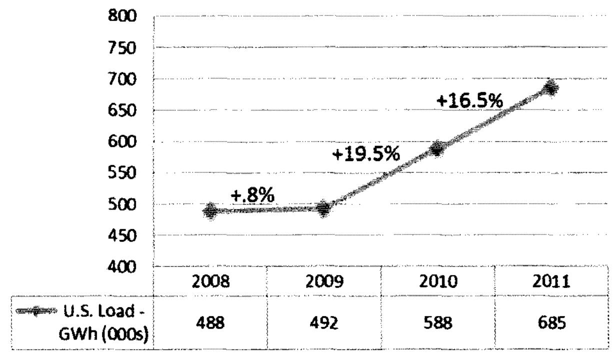
Rapidly increasing numbers of consumers of all sizes have exercised electric choice at the same time electric usage in the United States has essentially flat-lined during the recent economic doldrums. As represented in Charts 1 and 2, between 2008 and the fourth quarter of 2011, although overall electric usage in the continental United States declined by slightly less than 1% (Chart 1), retail choice in the 18 choice jurisdictions surged by 40% (Chart 2).

Chart 1: No Growth in Total Continental U.S. Electricity Load 2008-2011



Source: U.S. Energy Information Administration (EIA)

Chart 2: 40% Growth in Retail Competitive Electricity Load (18 Jurisdictions) 2008-2011 (% year over year)



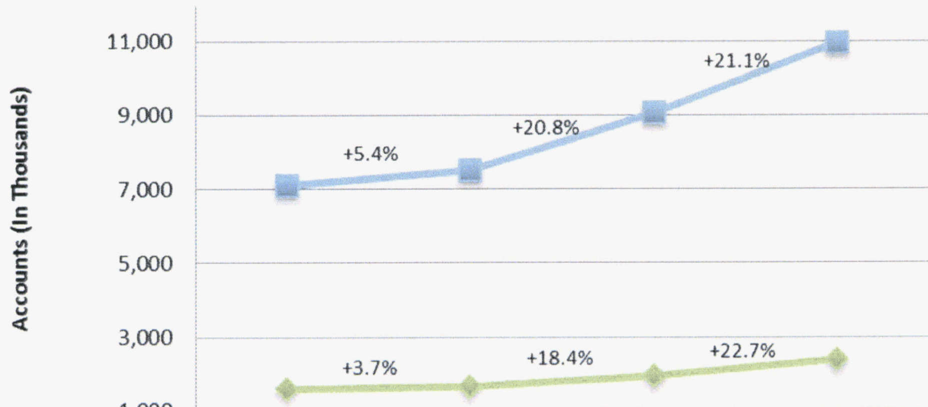
Source: KEMA Retail Energy Outlook, January 2012

Customarily, retail electric choice development has been in the non-residential customer segment, which accounts for more than three-fifths of electric usage in the country. This sector, often referred to as commercial and industrial (C&I) customers, includes factories, commercial businesses and buildings, educational and medical facilities and a wide range of governmental and public service functions.

Notably, however, smaller businesses are increasingly migrating to choice as larger customers demonstrate the benefits of choice and as competitive suppliers expand their marketing efforts. In addition, since 2009, there has been a tremendous increase in shopping among residential customers, both through individual supply contracts and through competitive aggregation programs. States have lowered regulatory hurdles to facilitate engagement between residential customers and competitive suppliers. With increasing uniformity in the rules-of-the-game, residential customers have demonstrated an appetite for savings, innovation, flexibility and efficiency.

As shown in Chart 3 below, since 2008, the total number of customer accounts served under choice arrangements grew by over 53% to over 13.3 million. Residential accounts served by competitive suppliers have increased by over 3.8 million, or over 54%, to nearly 11 million. The number of non-residential accounts served competitively has increased by over 800,000 to nearly 2.4 million – a jump of more than 50%.

Chart 3: 53% Growth in Competitive Retail Electricity Customer Accounts 2008-2011 (% year over year)



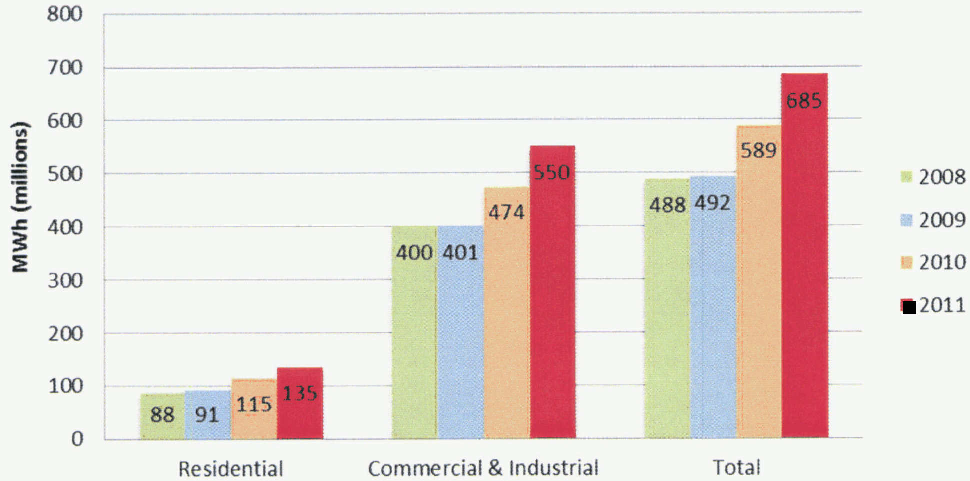
	2008	2009	2010	2011
Residential	7,111	7,493	9,049	10,957
C & I	1,583	1,641	1,943	2,385

Source: KEMA Retail Energy Outlook, January 2012

KEMA calculates that, by the fourth quarter of 2011, an annualized volume of about 685 million MWh of electric load was being competitively served in the United States. As indicated in Chart 4 below, the residential market accounted for 134 million MWh and the commercial/industrial segments accounted for 551 million MWh. In just the three years between 2008 and 2011, residential electric load served competitively increased 52.6% and commercial-industrial load by 37.8%. In no year did total electric load served under competitive supply contracts decline.

Table 1 in the Appendix details 2011 competitive volumes in each of the 18 retail electric choice jurisdictions as a percent of eligible electric load and as a percent of total end-use consumption.

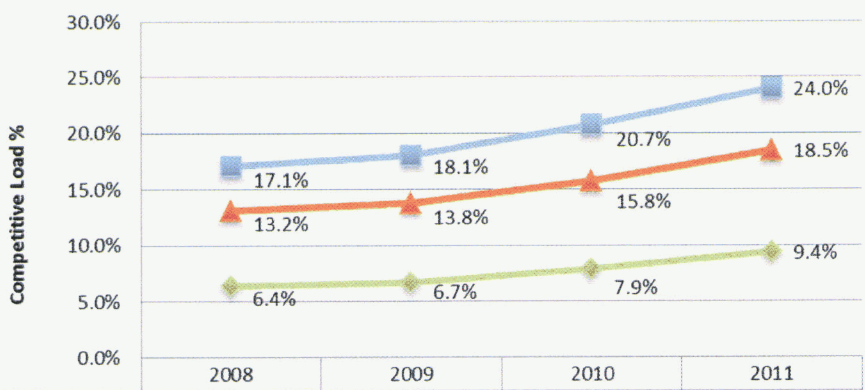
Chart 4: Annual Retail MWH Competitive Electricity Load by Customer Class (2008-2011)



Source: KEMA Retail Energy Outlook, January 2012

Shopping in the 18 retail choice jurisdictions now comprises over 33% of eligible commercial and industrial accounts, representing more than 68% of non-residential electric load, and more than 22% of eligible residential customer accounts, representing more than 31% of residential usage.[11] In 2011, 18.5%, or almost one out of every five kWh consumed in the United States was served competitively (as depicted in Chart 5 on the following page) and there is little doubt that in 2012 the 20% threshold will be crossed. This is a remarkable transformation in little more than a dozen years for an industry characterized for a century by vertically integrated monopoly utilities.

Chart 5: Competitive Load as a % of Total Continental U.S. (2008-2011)



	2008	2009	2010	2011
C & I	17.1%	18.1%	20.7%	24.0%
Total	13.2%	13.8%	15.8%	18.5%
Residential	6.4%	6.7%	7.9%	9.4%

Source: KEMA Retail Energy Outlook, January 2012 and EIA

RETAIL COMPETITION GIVES CONSUMERS ACCESS TO THE BENEFITS OF COMPETITIVE WHOLESALE ELECTRIC MARKETS

The expansion of retail electric choice in the United States in an otherwise challenging economy is no accident. As competition advocates predicted at the outset, robust, well-functioning competitive wholesale electric markets allow prices to adjust quickly to reflect supply and demand realities.

Over one-third of electric generation in the country is now supplied by independent (non-utility) power plants. Wholesale power transactions, which include both sales from independent power plants and sales from utility-owned generating stations to other utilities or to competitive retail suppliers, are almost all market-priced rather than rate-regulated by the Federal Energy Regulatory Commission (FERC).

Wholesale prices have declined substantially. Flat demand due to a slow economy and more efficient electric use by consumers across the board has reduced prices. Even more important has been the dramatic fall in natural gas prices due to abundant domestic supplies.[12]

Most significantly, competitive retail electric markets enable consumers to benefit quickly from lower wholesale prices.[13] In contrast, customers in monopoly-regulated markets do not, and cannot, see these price signals. Indeed, an inescapable paradox in monopoly utility regulation is that when supply exceeds demand (and other factors are held constant), prices do not decline, but must increase to cover fixed costs.

Michigan, where retail choice is limited in the two major utility service areas to 10% of total electric load, provides a compelling example of the problem. Since Michigan enacted the 10% limits in 2008, incumbent utilities have increased generation rates at the very same time wholesale electric prices decreased significantly.

C&I customers account for all of the approximate 9.25 million MWh that Consumers Power and Detroit Edison (DTE) report as served competitively.[14] In the hope of escaping higher fixed utility rates which do not reflect declining wholesale prices, well over 7,000 C&I customers, accounting for 6.5 million MWh of load, have joined long waiting lists seeking to access the lower prices available only to the fortunate customers who made it under the 10% cutoff.[15]

The C&I customers who must buy their electric supply from the local utilities pay between 6.5¢ and 8.5¢/kWh, excluding delivery, depending on customer size and utility territory. Conservatively estimating the average utility supply at 7¢/kWh versus a conservative estimate of 5¢/kWh for market-priced supply, represents a 2¢/kWh difference. Applying that 2¢ differential to just the 6.5 million MWh of load for the 7,000 customers on the Consumers and Detroit Edison waiting lists, represents lost savings annually of $130 million, massive savings these customers could otherwise invest to grow their businesses in Michigan. Fueling the rapidly growing waiting lists are many thousands of other customers who would leap at a savings of 2¢/kWh – and the resulting multiple millions of dollars in savings.

Market prices, however, are not the sole driver of vibrant, competitive retail electric markets. Competitive suppliers also offer innovative products and services, contractual terms, information, efficiency and supply portfolios to match their customers' individual needs.[16] Energy price risk can be managed in ways consistent with a customer's risk tolerance. Contractual periods can vary widely, from hourly to multi-year, and customers can select among clean energy options. Residential customers are starting to see pre-pay and other conveniences. Such innovative options, if available at all from traditionally regulated utilities, are generally reserved for only the largest customers.

NEW CHOICE STORIES – SUSTAINED DEVELOPMENT AND SUSTAINABLE RESULTS

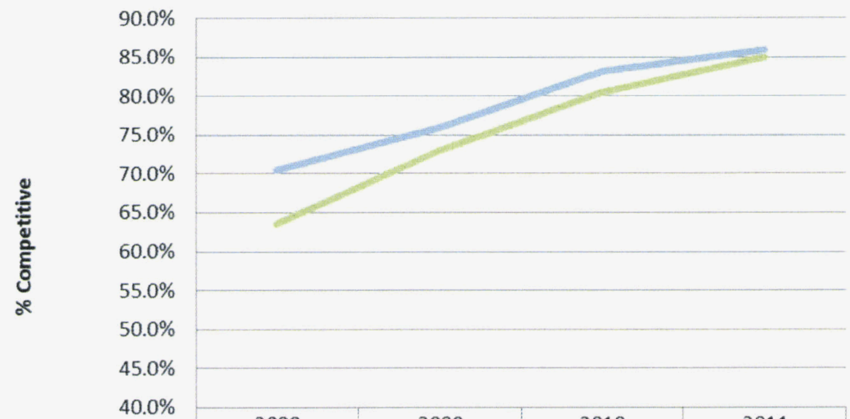
This updated report pays special attention to seven jurisdictions. Four states offer important examples of substantial progress since 2008 in both C&I and residential choice: Connecticut, New Jersey, Ohio and Pennsylvania. Two other states, Illinois and Maryland, which have had strong C&I choice markets for some time, are now experiencing significant growth in residential choice. Finally, since 2008, Rhode Island has doubled the level of C&I customer load served competitively. Other states such as Texas and New York have also experienced strong progress during the period but are not reviewed in-depth in this report.

Connecticut: Residential Customers and C&I in Tandem

Although Connecticut introduced retail electric choice in 1998, it was not until 2006 that choice began to take hold. In most states, larger C&I customers have been the first to embrace choice, followed several years later by residential customers. In Connecticut, however, choice among C&I and residential customers has grown largely on parallel paths. While C&I customers have accessed competitive opportunities in greater proportions than have residential customers nationally, the trends in Connecticut have been well correlated. This is due in large part to the state's implementation of market-based utility standard offer service that is priced and acquired through a competitive process with laddered portfolios.

Chart 6 below shows that between 2008 and 2011, the percentage of eligible C&I electric load served competitively rose from 63.6% to 84.9% for Connecticut Light and Power (CL&P), and from 70.5% to 85.9 for United Illuminating (UI). Further, Chart 7 on the following page shows that during the same time period, percentages for residential choice rose from 6.6% to 44.2% for CL&P and from 9.9% to 52% for UI.

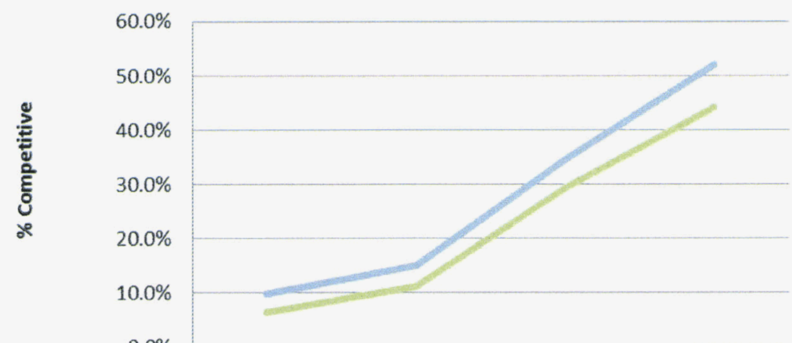
Chart 6: Connecticut
% of Eligible C & I Load Served Competitively (2008-2011)



	2008	2009	2010	2011
United Illum. Co.	70.6%	75.9%	83.2%	85.9%
CT L&P	63.6%	73.0%	80.4%	84.9%

Source: KEMA Retail Energy Outlook, January 2012

Chart 7: Connecticut
% of Eligible Residential Load Served Competitively (2008-2011)



	2008	2009	2010	2011
United Illum Co.	9.9%	15.1%	34.7%	52.0%
CT L&P	6.6%	11.3%	29.5%	44.2%

Source: KEMA Retail Energy Outlook, January 2012

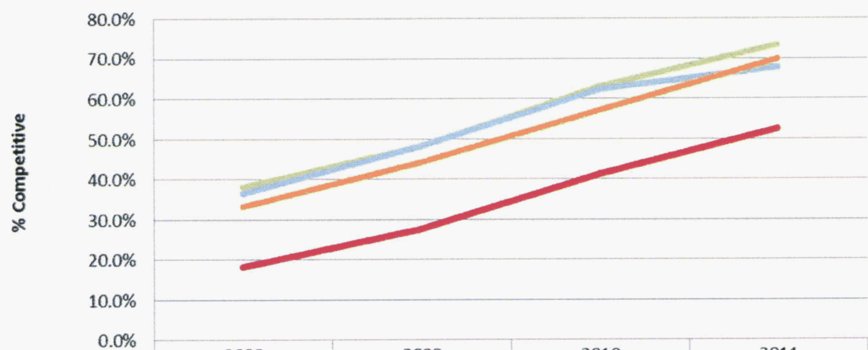
Furthermore, Connecticut regulators have played a direct role in helping facilitate customer education and in linking residential and small business customers with competitive providers through the CTEnergyInfo website.[17] In addition to the list of competitive providers and frequently-asked-questions customarily found on utility regulatory websites, the Connecticut website provides residential and small business customers with the opportunity to easily compare prices across the full range of options, including competitive and utility standard offer supply, differing levels of renewables content and several fixed and variable-priced products.

New Jersey: A Garden State for Electricity Choice

Since implementing choice a decade ago, New Jersey has had a more typical growth pattern than Connecticut's, with non-residential customer choice growing fairly steadily, but residential choice only recently taking hold.

As represented in Charts 8 and 9 below, between 2008 and 2011, eligible C&I load served competitively across the state's four utility service areas rose from between 18% and 38% to between 52% and 73%, whereas only in the past year has residential choice increased, from 1% in 2008 to between 8% and 14% in those four utility service areas in 2011.

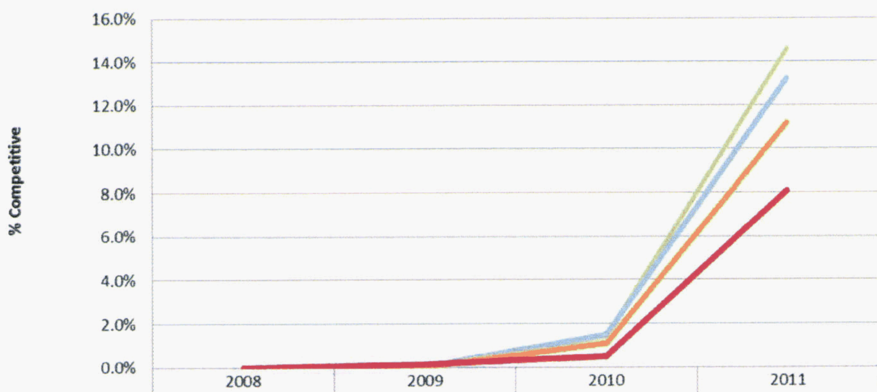
Chart 8: New Jersey
% of Eligible C & I Load Served Competitively (2008-2011)



	2008	2009	2010	2011
Atlantic City	38.3%	48.4%	63.2%	73.4%
Jersey Central	36.6%	48.3%	62.5%	67.8%
PSEG	33.3%	44.4%	57.3%	69.9%
Rockland	18.2%	27.6%	41.3%	52.5%

Source: KEMA Retail Energy Outlook, January 2012

Chart 9: New Jersey
% of Eligible Residential Load Served Competitively (2008-2011)



	2008	2009	2010	2011
Atlantic City	0.0%	0.0%	1.4%	14.6%
Jersey Central	0.0%	0.0%	1.5%	13.2%
PSEG	0.0%	0.0%	1.1%	11.2%
Rockland	0.0%	0.1%	0.5%	8.1%

Source: KEMA Retail Energy Outlook, January 2012

Once again, access to more market-reflective pricing has been key. Since the 2008 auction, larger industrial and commercial customers have had only hourly service available for default service, but residential and small business customers had fixed-price standard offer service comprising a composite of three years of procurement auctions. The most recent New Jersey procurement in early February 2012, which secured wholesale supply for all investor-owned utilities from numerous wholesale suppliers, resulted in reduced standard offer prices. Nonetheless, prices under the laddered procurements may well encourage more residential and small business customers to shop to obtain prices based on the current wholesale market.

Ohio – Utility Affiliates and Municipal Aggregation

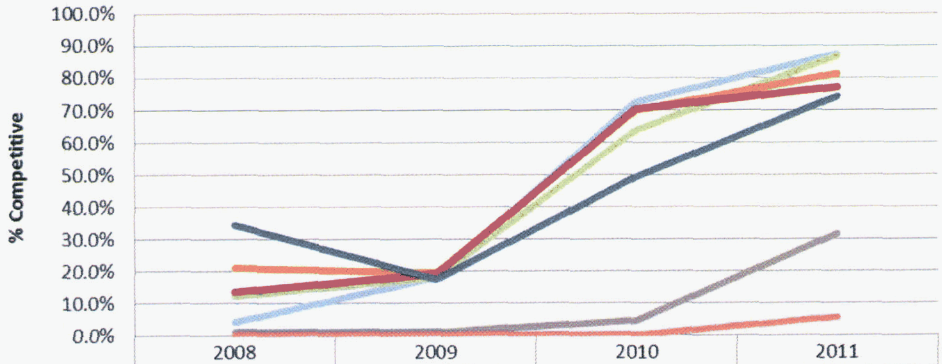
The surge in electric choice in Ohio underscores the basic reality that electric choice is a state-by-state, utility-by-utility phenomenon.

The Public Utilities Commission of Ohio (PUCO) conducts heavily contested reviews of each utility's "Electric Security Plan." Two key factors suggest Ohio will remain committed to increasing competition rather than reinstating traditional cost-of-service ratemaking. First, the emergence of large shale gas supplies in Ohio and neighboring Pennsylvania indicates long-term low natural gas prices will continue to mitigate wholesale power prices. Further, with some Ohio utilities firmly committed to choice, others that may remain ambivalent will find it extremely difficult to recreate the *status quo ante* if the result would be that some Ohio customers would be free to choose while others are held captive.

Second, municipal aggregation in Ohio is moving thousands of residential customers from utility-bundled service to market-priced power provided through their local governments and delivered by the utility. These municipal aggregation programs, with opt-out provisions permitting customers to shop for better individual deals with competitive suppliers, are one of ways the competitive market can deliver reasonably priced, reliable electricity.

As shown on the following page in Charts 10 and 11, although the surge in retail choice in Ohio has been uneven to date, it is nonetheless impressive and likely augurs continued growth. First, a majority of C&I load statewide has shifted to competitive market supply, with more than three-fourths of C&I load having switched in all utility territories other than the two served by American Electric Power affiliates. Second, more than two-thirds of residential load in First Energy's three utility service areas is being served competitively. In the Duke-owned Cincinnati Gas & Electric service area, more than a third of residential load has switched.[18]

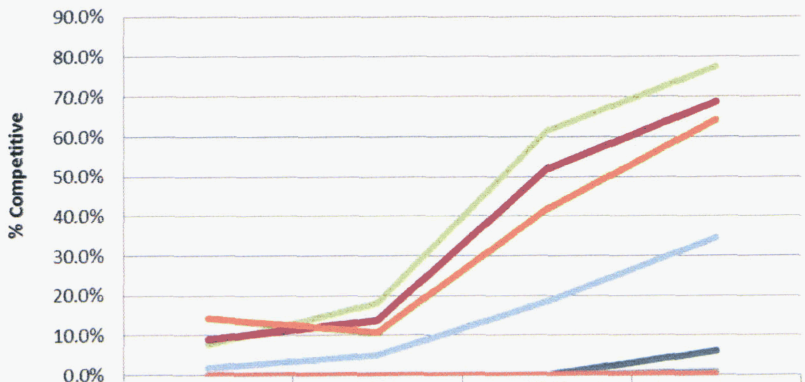
Chart 10: Ohio
% of Eligible C & I Load Served Competitively 2008-2011



	2008	2009	2010	2011
CG&E	4.3%	18.2%	72.4%	87.2%
Cleveland	12.5%	18.0%	63.7%	86.7%
Ohio Edison	20.9%	19.5%	69.9%	81.1%
Toledo Edison	13.5%	19.0%	70.4%	77.0%
Dayton P & L	34.4%	17.4%	49.5%	74.2%
Columbus & So.	1.0%	1.1%	4.7%	31.5%
Ohio Power	0.0%	0.0%	0.0%	5.5%

Source: KEMA Retail Energy Outlook, January 2012

Chart 11: Ohio
% of Residential Load Served Competitively 2008-2011



	2008	2009	2010	2011
Cleveland	7.8%	18.3%	61.5%	77.7%
Toledo Edison	9.1%	13.9%	52.0%	68.7%
Ohio Edison	14.5%	11.0%	41.9%	64.3%
CG&E	1.7%	5.1%	18.4%	34.4%
Dayton P & L	0.0%	0.0%	0.0%	6.0%
Columbus & So.	0.0%	0.0%	0.0%	0.8%
Ohio Power	0.0%	0.0%	0.0%	0.1%

Source: KEMA Retail Energy Outlook, January 2012

Pennsylvania – Vigorous Regulatory Leadership

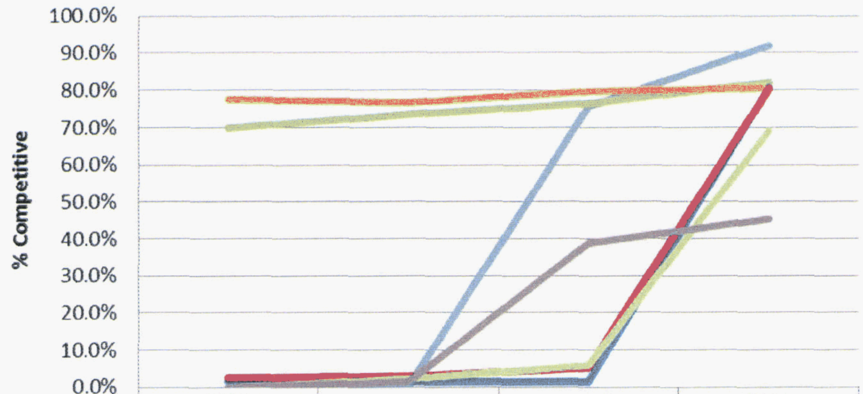
Pennsylvania, like Ohio, illustrates that development of retail electric choice usually precedes utility-by-utility until success prompts greater statewide uniformity in the rules of the game. Pennsylvania also helps reminds us that support for retail electric choice has been bipartisan, just as has been the case with federal support for competitive wholesale markets. Successive Pennsylvania administrations, Democratic and Republican, have supported retail electric choice. The current Pennsylvania Public Utility Commission (PUC) is seeking to enhance default service structure, rules and processes to further increase shopping and harmonize rules-of-the game across utilities.

After rate caps terminated statewide at the end of 2010, implementation of utility purchase of receivables (POR) and utility consolidated billing (UCB) reduced duplicative transaction costs, helping enable suppliers to optimize the benefits of competitive wholesale markets for their retail customers.

The Pennsylvania PUC's active role as educators as well as regulators has contributed substantially to the growth of retail electric choice. Over several years, PUC members traveled widely to explain and encourage retail electric choice, visiting with a wide range of business and community organizations and with the news media.

During the past three years, the growth in retail electric choice in both the C&I and the residential segments has been stunning. In fact, as shown in Chart 12, C&I electric load in Pennsylvania will likely become totally competitive over time.

Chart 12: Pennsylvania
% of Eligible C & I Load Served Competitively 2008-2011

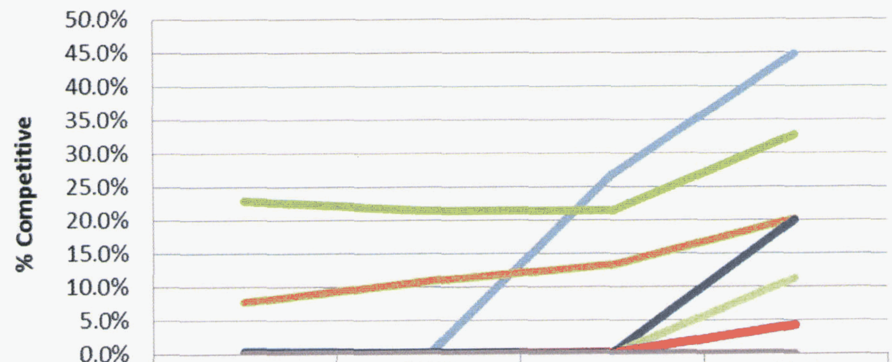


	2008	2009	2010	2011
PPL	0.1%	0.1%	75.6%	92.0%
Duquesne	69.8%	73.4%	76.4%	82.1%
Penn Power*	77.6%	76.7%	79.7%	80.7%
Peco	1.8%	1.5%	1.5%	80.5%
MetEd / Penelec*	2.5%	2.9%	5.2%	80.5%
West Penn*	0.0%	2.2%	5.9%	69.2%
UGI	0.0%	1.4%	38.9%	45.3%

Source: KEMA Retail Energy Outlook, January 2012
**First Energy*

Even without municipal aggregation, many Pennsylvania residential customers have switched to competitive suppliers since rate caps expired. As depicted in Chart 13 below, about one-fourth of the residential load in the Duquesne Light service area is shopping. PPL residential choice already is about 45% and in PECO over 20% of residential load has switched. Increasing numbers of residential customers in the three First Energy utility areas are shopping. Customers in UGI, a very small utility, however, have yet to enter the choice arena.

Chart 13: Pennsylvania
% of Eligible Residential Load Served Competitively 2008-2011



	2008	2009	2010	2011
PPL	0.0%	0.0%	26.8%	44.8%
Duquesne	23.0%	21.3%	21.4%	32.7%
Penn Power*	7.7%	10.8%	13.2%	20.2%
Peco	0.2%	0.2%	0.2%	19.9%
West Penn*	0.0%	0.0%	0.0%	11.2%
MetEd / Penelec*	0.0%	0.0%	0.0%	4.3%
UGI	0.0%	0.0%	0.0%	0.0%

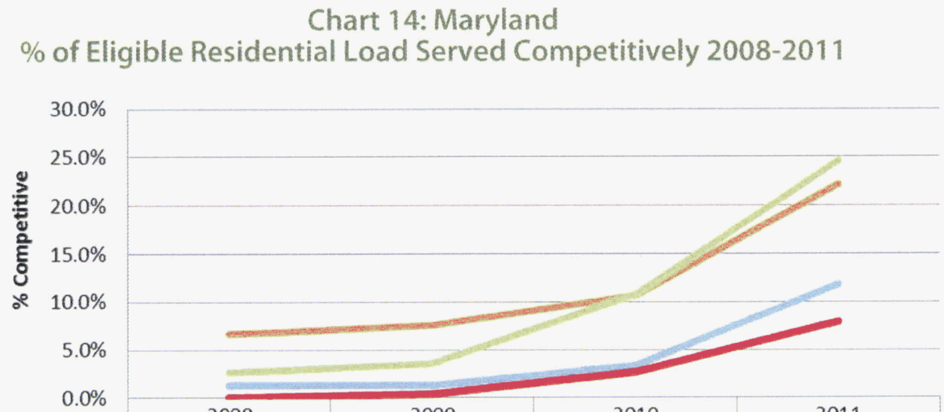
Source: KEMA Retail Energy Outlook, January 2012
**First Energy*

Maryland and Illinois: Unlocking the Door for Residential Customers

Maryland and Illinois have had fairly similar experiences with the development of retail electric choice, with early shopping by C&I customers in most utility areas, but delayed residential switching.

Competitive suppliers serve well over three-fourths of all eligible non-residential load in both states, with more than half of all electric consumption in each state shopping. Since 2008, both states now have also promoted greater residential shopping by implementing POR and UCB. The Maryland Public Service Commission authorized UCB and POR for residential suppliers in 2008 and implemented both in mid-2010. Similarly, after lengthy proceedings and negotiation among utilities and competitive suppliers, Illinois implemented POR and UCB for residential customers in mid-2011.

Chart 14 below illustrates that in Maryland's four utility service areas, shopping has moved from a range of zero to less than 7% in 2008 to about one-fourth of residential load switching to choice in Baltimore Gas & Electric and PEPCO, the state's two largest utilities. One indication of the considerable momentum behind residential choice is that over a dozen licensed competitive suppliers are actively marketing to residential customers in Maryland.[19]



	2008	2009	2010	2011
Pepco	6.6%	7.6%	10.7%	22.2%
BG & E	2.7%	3.6%	10.8%	24.6%
Delmarva	1.3%	1.3%	3.3%	11.8%
Potomac Edison	0.0%	0.4%	2.7%	7.9%

Source: KEMA Retail Energy Outlook, January 2012

In Illinois, UCB and POR have had an immediate and significant impact. In the Commonwealth Edison service territory that accounts for about 80% of Illinois electricity consumption, residential choice has gone from near zero at the start of 2011 to 6.5%. Two dozen alternative retail electricity suppliers (ARES) have completed the licensing process with the Illinois Commerce Commission to serve residential customers.[20]

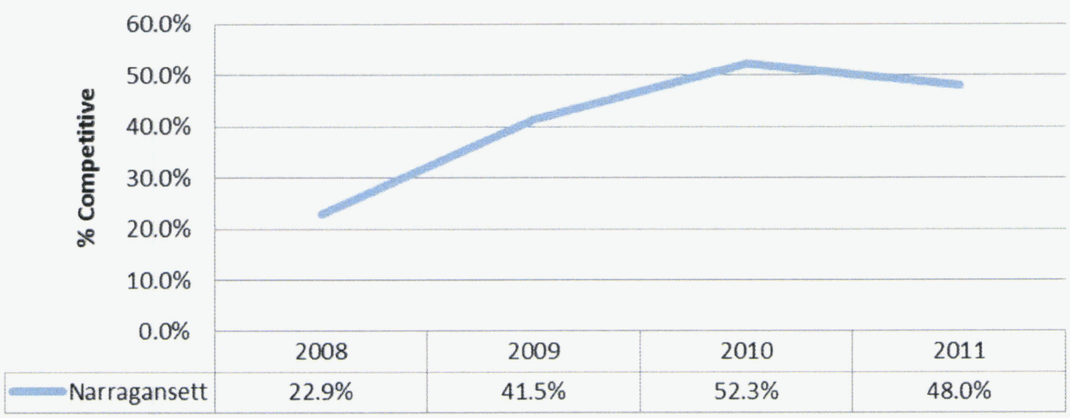
Municipal aggregation is poised to play a significant role in Illinois. So far, 20 municipalities have qualified under the aggregation law. In the 2012 primary and general elections, 277 local referenda are scheduled to decide whether local governments will enter the competitive electric market on behalf of their residential customers.[21]

The Illinois experience with electric industry restructuring is an interesting case study in the ongoing effort to better understand the impact of restructuring on prices. Table 2 in the Appendix illustrates the ratio of average, all-in electric prices, including delivery, paid by all end-use customers in Illinois to the average prices for all U.S. consumers in the 21-year period 1990-2011. Prior to the introduction of retail competition, average Illinois electric prices had consistently been higher than the national average. Retail electric choice was phased in over a several year period starting in October 1999 and by 2001, average Illinois electric prices had fallen below the national average and have stayed lower every year since.

Rhode Island: First in the Field

Rhode Island was the first state in the country to deliver a kilowatt-hour of competitive retail electricity in July 1997.[22] Rhode Island's pathway to increased electric choice can best be understood as part of the general and simultaneous migration of the New England region to industry restructuring. There is no spectacular story to tell about this small jurisdiction other than there has been slow but steady growth in retail choice since its commencement. As indicated in Chart 15 below, since 2008 the share of eligible C&I load served competitively has doubled, however, there was a slight downturn in the percentage of eligible load served in 2011.

Chart 15: Rhode Island
% of Eligible C & I Load Served Competitively 2008-2011



Source: KEMA Retail Energy Outlook, January 2012

RULES-OF-THE-GAME MAKE THE DIFFERENCE

As highlighted in COMPETE's 2010 report, fair, uniformly applied rules-of-the-game designed to create and maintain a level playing field for competition are the mainstay of sustained growth of retail electric choice. The many examples of substantial progress detailed in this 2012 update can be attributed in great part to competitive jurisdictions uniformly applying clear rules-of-the-game. Texas provides an outstanding example of the importance of establishing uniformly applied pro-competition rules-of-the-game.

Rather than constructing a hybrid model mixing legacy monopoly structures and processes with retail electric choice, Texas committed fully to disconnecting the delivery utility itself from responsibility for supply. Policy makers and regulators in Texas have stayed the course even as energy prices fluctuated. Texas now has several years of successful experience with 100% of customers in investor-owned utility delivery service areas securing their supply from a combination of competitive suppliers which serve three-fourths of all energy load and utility affiliates separate from the wires company serving the remainder, mainly residential and small business.

Customer choice has also flourished in New York. New York has proven states can achieve substantial growth in retail electric choice on a utility-by-utility basis without leveraging specific restructuring laws. New York has robust C&I customer switching rates comparable to those in other states with active retail choice programs, and has experienced strong residential shopping, with several utilities having between a fourth and a third of their residential customer load served competitively.

Stable regulation and ***clear rules*** now characterize the great majority of the 18 retail electric choice jurisdictions examined in this report. To enable sustained growth in choice, regulators and policymakers set clear goals and policies, and adjust them only as needed to stay on target. Generally, over the past decade, regulatory developments have been positive in most retail electric choice markets. There are exceptions, however, such as California and Michigan, where regulatory changes that limit shopping have seriously disrupted the progression of customer choice.

In 2012, ***wholesale competition, open transmission access*** and *organized regional wholesale power markets* are widely accepted. Importantly, even among those who continue to oppose retail electric choice, there is a growing acceptance of robust wholesale competition, open access to transmission and the establishment of organized regional wholesale power markets. The potential problems cited in the past by skeptics of open access and organized regional markets have not materialized and reliability has been maintained. Further, prices have responded promptly to market conditions, conveying accurate signals to market participants, while market operation rules continue to be fine-tuned.

At the Federal level, FERC has stayed the course with the strong commitment to competitive market reforms it has pursued since the 1980s under both Democratic and Republican administrations and differing Congressional majorities.

At the state level there are five key conditions that continue to frame the opportunity for customers and competitive suppliers to fully and effectively engage with one another.

Cost-based delivery rates have evolved in most jurisdictions, replacing bundled rates that discriminated between retail electric choice customers and those remaining on utility default service. In contrast with non-retail choice states, competitive states work hard not to co-mingle costs and pricing for delivery and supply services for customers who continue to take supply service from the local utility.

Market-based default service has had the most substantial impact on the growth of retail electric choice. The elimination of stranded cost charges from generation rates, rate caps or other artificial price interventions and supply cross-subsidies has highlighted for consumers the direct link between the market price of generation and retail rates. Increasingly, policy makers in competitive retail electric markets have recognized the value of promoting supply procurement protocols for default service that better reflect market conditions.

Customer Data and Electronic Data Interchange (EDI) arrangements have become more routine and effective, with large numbers of competitive suppliers ably participating in sophisticated data exchange with utilities and, in turn, with customers. The growing commitment to Smart Grid deployment, including advanced metering infrastructure (AMI), holds substantial potential for timely, multilateral communication among customers, suppliers and delivery utilities. As noted elsewhere in this paper, KEMA and ABACCUS have highlighted the growth of innovative service offerings in parallel with the surge in customer choice.[23]

Utility Consolidated Billing (UCB) and Purchase of Receivables (POR) have proven to be linchpins for the growth of residential customer choice, as they help mitigate transaction costs which otherwise would deter supplier participation. UCB and POR help leverage transaction efficiencies in metering, billing, capital formation and risk management. In Maryland, Pennsylvania and Illinois, for example, implementing UCB and POR in recent years has supported a rapid expansion of residential choice.

Customer Education and the Promotion of Choice increasingly have migrated from state regulators to competitive suppliers, utilities and customers themselves, with regulators focusing primarily on monitoring, data collection, and developing and enforcing market rules. C&I customers no longer require guidance or positive reinforcement from regulators. The current educational mission is to promote residential and small non-residential customers shopping by providing them efficient access via the web to pricing and other terms so they can easily compare to default offerings. The Internet has become a standard conduit for electric shopping as it has for most other products. The November 2011 ABACCUS report notes that as retail electric choice markets mature, it may be enough for regulators to host websites and otherwise facilitate transparency and access for customers to competitive suppliers.[24] Municipal aggregation programs in Ohio and Illinois also can facilitate switching and access to choice for residential and small business customers. Customers can opt-out and choose to remain on utility default service or elect individually to go with a competitive retail supplier.

State regulators, retail suppliers, customers and distribution utilities have improved their support of these five conditions by learning from their own experiences as well as those in other jurisdictions. Although retail choice will continue to have a state-by-state, utility-by-utility flavor, the ongoing harmonization of market rules and processes with increasingly similar rules-of-the-game will encourage greater consumer and supplier participation.

EMBEDDING ELECTRICITY CHOICE

The year 2012 may one day be recognized as when electricity choice became firmly embedded across the full range of customer classes. It has become increasingly clear that any remaining objections to retail electric choice are less about the interests of customers than about the interests of other parties.

There are several reasons. First and foremost, far larger numbers of residential customers are likely to exercise choice and C&I customers will continue to want unobstructed access to favorable wholesale prices. Second, fewer states with competitive retail markets see a need to provide ongoing comprehensive utility-based supply service. Third, competitive retail electric supply's growing market share and strong empirical evidence of its success will counter customer choice opponents and skeptics.

With the solid record of electric choice during the 2008-2011 economic downturn, consumers and suppliers will likely place increasing pressure on policy makers and regulators in California, Michigan, Montana and Oregon to restore their full right to shop. Pressure will grow for Arizona, Nevada and Virginia, once on the path to choice, to reconsider policies preventing retail electric competition, given the demonstrated benefits enjoyed by consumers in choice states.

The benefits of choice in the 18 jurisdictions with retail electric choice highlight to consumers in monopoly states that the time has come to allow them to shop for competitive retail electric service as they already do for most services.

Market maturity has expanded retail electric choice from the largest commercial and industrial customers to small businesses and residential consumers. The complete transition in Texas from vertically-integrated investor-owned utility monopolies to a fully competitive model of suppliers separate from distribution utilities has demonstrated that retail electric choice is workable for all customer classes. Other states, New York among them, reinforce the growing empirical evidence that a restructured electricity industry serves all customers well.

LOOKING AHEAD

In just the past decade, retail electric choice has transformed an industry that for a century was predicated on the certainty of regulated electric monopolies. The 18 domestic choice jurisdictions are not alone in this transformation. Many European Union members rely to a considerable extent on retail electric choice and competitive wholesale power markets, as does much of the highly developed English-speaking world from Britain to Australia and New Zealand.

The most recent significant movement toward competition in the electric industry is Japan's decision to introduce customer choice and supply competition in the wake of the 2010 tsunami and resulting nuclear power crisis. Constricted energy supplies and concerns about outdated management and safety practices rooted in a monopoly industry structure have prompted the Japanese government to actively consider competitive reforms of the industry.[25]

Widespread acceptance of deploying innovative Smart Grid technologies across the network has paralleled the surge in electric choice. Beyond improvements in reliability of delivery service, including outage prevention and faster outage recovery, Smart Grid technologies can dramatically expand the capabilities of customers to interact with the network and the market. The arrival of the digital revolution will be just as technologically transformative for the electric industry as it has been for the telecommunications sector.

Residential and C&I customers, surrounded by intelligent appliances and equipment interacting with the network and the electric market, will be empowered as never before. The traditional one-way relationship of the electric industry to customers will become a multilateral communications network. Customers will be able to consume power when it is most efficient or environmentally responsible to do so and can contribute to improved capacity factors and a more stable and reliable power grid through well-timed demand response.

Innovative Smart Grid technologies will help render the arguments of choice skeptics even more obsolete, both technologically as well as economically. As Smart Grid technologies emerge, the entire range of customers, from the most sophisticated large industrial and commercial to small businesses and homeowners, will have easy access to the information required to manage their energy usage and make informed choices. All customers will be able to choose from many innovative options ranging from real-time to fixed-price fully hedged supply. These increasing customer benefits will ensure sustainable growth for retail electric choice.

APPENDIX

Table 1 below shows the volume of retail electric load as a percentage of load actually eligible for retail choice and as a percentage of total electric load in each of the 18 jurisdictions. In some states, municipal utilities and rural cooperatives serve significant load and therefore the percentage of total load served competitively may be considerably smaller than the percentage of eligible load in investor-owned utilities.

TABLE 1

2011 Non-Residential/Residential Competitive Sales as Percent of 2011 Eligible Load & as Percent of EIA Reported Total Statewide C&I or Residential Load						
Jurisdiction	Non-Residential Competitive Load			Residential Competitive Load		
	GWh	Eligible %	Total %	GWh	Eligible %	Total %
California	21,939	17.80%	13.40%	101	0.10%	0.10%
Connecticut	13,363	85.20%	78.90%	5,583	45.60%	43.00%
Delaware	4,068	75.00%	62.00%	115	3.80%	2.50%
DC	8,318	83.90%	87.50%	127	6.30%	6.20%
Illinois	71,406	80.00%	75.20%	2,211	5.40%	4.70%
Maine	4,541	68.60%	64.50%	24	0.60%	0.50%
Maryland	28,514	81.70%	78.50%	5,056	20.70%	18.50%
Massachusetts	23,094	76.20%	64.50%	2,199	12.70%	10.50%
Michigan	7,999	100.00%	11.50%	0	0%	0%
Montana	2,453	100.00%	27.60%	1	0%	0%
New Hampshire	3,380	57.20%	52.80%	9	0.20%	0.20%
New Jersey	33,325	79.40%	70.40%	3,680	12.30%	12.50%
New York	54,795	68.20%	59.30%	8,800	22.50%	17.20%
Ohio	52,746	58.60%	52.30%	14,872	33.10%	27.90%
Oregon	959	5.30%	3.50%	0	0%	0%
Pennsylvania	75,232	81.80%	80.00%	12,265	23.30%	22.40%
Rhode Island	2,204	48.00%	47.90%	32	1.00%	1.00%
Texas	142,442	100.00%	64.30%	78,810	100.00%	55.10%
TOTAL	550,778	66.20%	52.80%	133,885	31.30%	22.10%

Table 2 below compares average electric prices per kWh, including delivery, paid by all sectors in Illinois with the average price in the United States 1990-2011. The 1997 electric restructuring legislation in Illinois phased-in retail electric choice, starting with portions of C&I load in October 1999. In the period 1990-2000, average Illinois prices were consistently higher than the national average. In the period 2001-2011 Illinois prices have been consistently lower than the national average.

TABLE 2 (Data and Chart)

Total Electric Industry - All Sectors			
	Average Rate (cents/kWh)		
Year	Illinois	US	Ratio
1990	7.49	6.57	1.14
1991	7.63	6.75	1.13
1992	7.69	6.82	1.13
1993	7.75	6.93	1.12
1994	7.41	6.91	1.07
1995	7.69	6.89	1.12
1996	7.69	6.86	1.12
1997	7.71	6.85	1.13
1998	7.46	6.74	1.11
1999	6.96	6.66	1.05
2000	6.94	6.78	1.02
2001	6.90	7.25	0.95
2002	6.94	7.13	0.97
2003	6.86	7.38	0.93
2004	6.80	7.55	0.90
2005	6.95	8.05	0.86
2006	7.07	8.77	0.81
2007	8.46	8.98	0.94
2008	9.26	9.54	0.97
2009	9.33	9.89	0.94
2010	9.13	9.83	0.93
2011	9.01	9.99	0.90

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[1] For purposes of this report, 18 jurisdictions, 17 states and the District of Columbia, are considered to have active electricity competitive choice programs, although some of the jurisdictions have a variety of limitations and restrictions that place significant constraints on the exercise of customer choice. Jurisdictions with broadly open choice programs are Connecticut, Delaware, the District of Columbia, Illinois, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island and Texas. Four others – California, Michigan, Montana and Oregon –, have notable competitive demand and customer receptivity to choice despite rather daunting regulatory and legislative obstacles to the exercise of choice. Nevada and Virginia, which once had the beginnings of customer choice programs, are not included.

[2] *Customer Choice in Electricity Markets: From Novel to Normal*, by Philip R. O'Connor, Ph.D., November 15, 2010, a research paper commissioned and published by The COMPETE Coalition. The paper can be found at the COMPETE website http://www.competecoalition.com/files/Customer-Choice-In-Electricity-Markets_0.pdf.

[3] DNV KEMA (KEMA at http://www.kema.com/Default.aspx) is a Netherlands-based global energy consultancy and information firm. The KEMA data base on competitive choice in electricity is indispensable for serious research on trends in the competitive electricity market. KEMA's quarterly reports provide detailed state-by-state and utility-by-utility data on eligible demand, competitively served customer accounts and volume and rates of switching to competitive supply. Importantly, these reports contain retrospective data and projections of likely future developments. The United States Energy Information Agency (EIA at http://www.eia.gov/) is the arm of the U.S. Department of Energy charged with collecting, disseminating and analyzing data across the energy spectrum. EIA has ably adapted its information-gathering methods to the realities of the restructuring electricity industry over the past two decades. Distributed Energy Financial Group LLC (DEFG at http://www.defgllc.com/) issues the "Annual Baseline Assessment of Choice in Canada and the United States" (ABACCUS). ABACCUS provides in-depth reviews of the legal background of choice in all relevant North American jurisdictions. While reporting on competitive volumes and switching rates at a high level, ABACCUS also focuses on pricing trends, numbers of competitive suppliers and rates jurisdictions on the degree of choice available.

[4] While California, Michigan, Montana and Oregon all currently have notable levels of demand exercising customer choice, each state has public policies in place that place varying significant limits on the ability of customers to engage with competitive suppliers. California grandfathered choice customers in in the wake of the state's "energy crisis" induced by its uniquely flawed market design, but prohibited new competitive customers until the state government had retired the high-priced contracts it entered into in a panic reaction at the time. Michigan, in the midst of growing interest and participation in choice by non-residential customers, succumbed in 2008 to protectionist pleas from incumbent utilities. Competition is capped at 10% of total demand in the territories of the two major investor-owned utilities and onerous conditions were placed on customers considering choice. Over 7,000 non-residential customers have signed on to waiting lists in the hope and anticipation of the caps being raised. In Oregon and Montana, while significant C&I demand is being served, new customers are effectively restricted from exercising choice.

[5] Electricity choice in California has never recovered from the period in 2000-2001 that is often called the "California Energy Crisis." In the legislative reaction that followed, existing choice customers were grandfathered and all others were locked into utility supply as long as high-priced contracts the state entered into during the price panic were still in place. Legislation in 2009 opened the door to modest, phased expansion of customers eligible for choice. The two first-come, first-served enrollment periods allowed so far, in April 2010 and 2011, resulted in immediate customer oversubscription and inevitable disappointment for customers who missed out on the extremely narrow opportunity afforded. The 2009 legislation had the unfortunate provision of making any further expansion of choice a function of further legislative determinations rather than of a Public Utilities Commission decision in response to market developments. A key difficulty in California is that while other states with choice programs have liquidated stranded costs, California has succeeded in building up a large stranded cost overhang that has been used to justify exit charges and other hindrances to the full realization of savings available from the competitive wholesale electricity market.

[6] Energy Choice Matters, January 13, 2012, Market Reports California phase IV Direct Access Cap Hit.

[7] In Arizona, no competitive power volumes ever flowed to customers following the 1998 enactment of a restructuring law due to a variety of regulatory infirmities in the choice program and litigation that invalidated the generation divestiture mandates in the law (see ABACCUS November 2011, p 31). In January 2012, a settlement involving Arizona Public Service (APS) will allow for large customers, capped at an aggregate total of 200 megawatts, to access competitive suppliers through APS. The arrangement under the settlement is termed a four year "experimental" tariff.

[8] Nevada and Virginia enacted legislation in the late 1990s aimed at moving to competitive retail choice but abandoned their efforts within just a few years. In Nevada, a handful of large customers, including casinos, were authorized by regulators to purchase competitive supply. However, competitive sourcing was mainly confined to a few large mining sites that continue to have market access. Virginia allowed for small volumes of competitive supply to flow for a number of years, but has now effectively shut down choice.

[9] *The Wall Street Journal* reported that on March 7, 2012 prices for natural gas deliveries in April 2012 fell to their lowest level since February 2002, "Natural Gas Touches Decade Low, *The Wall Street Journal*, March 8, 2012.

[10] EIA *Electric Power Monthly February 2012*, Table 5.4.B http://www.eia.gov/electricity/monthly/pdf/epm.pdf

[11] The seeming incongruity between the figure of 22% of eligible residential accounts being served competitively while 31% of residential demand is on choice contracts is largely accounted for by the greater average electric usage by residential customers in Texas, where 100% of eligible customers are served competitively, compared to many other competitive states. EIA state level electrical use data can be found at http://www.eia.gov/cneaf/electricity/esr/table5.html.

[12] EIA's Natural Gas Monthly, issued at the end of December 2011, shows that gas prices paid by electricity generators are at their lowest levels since 2002 and in many months of 2011 were about half the price levels in the same months in 2008 http://www.eia.gov/dnav/ng/hist/n3045us3m.htm. EIA's early release presentation of its schedule 2012 Annual Energy Outlook forecasts persistent long-term low natural gas prices and gas reserves that are about 40% greater than EIA estimates in 2008. The increase in reserve estimates is attributable in great part to shale gas development http://www.eia.gov/pressroom/presentations/howard_01232012.pdf.

[13] The November 2011 ABACCUS report issued by DEFG succinctly summarizes the situation its first page: "Policymakers throughout North America must understand that deliberate policy choices were made in successful jurisdictions to foster retail electricity competition. As a result, these places are experiencing lower prices that timely adjust to the lower fuel (power plant input costs) and electric commodity prices, and they are witnessing the offering of new products and services that consumers are embracing, "*Annual Baseline Assessment of Choice in Canada and the United States*", Distributed Energy Financial Group LLC, November 2011, p1. http://www.defgllc.com/content/login.asp?pid=275

[14] Michigan's limiting of retail competition to 10% of electricity demand is flexible only to the extent that customers will not be forcibly removed from choice if the volume cap falls below existing participation levels. This results in about 11% of current total demand being served under choice contracts. A reduction in the cap, however, does mean that, absent general growth in electricity, customers on the waiting list can only access choice once enough customers voluntarily exit choice so as to reduce participation levels below the 10% cap. The 9.25 million megawatt-hours reported by the two Michigan utilities as being served competitively is a higher figure than reported by KEMA at 8 million MWh.

[15] Consumers Power and DTE Energy maintain webpages about the cap calculations and the number of customers and demand awaiting choice. http://www.consumersenergy.com/content.aspx?id=2186&sid=107 and http://www.suppliers.detroitedison.com/internet/cap_tracking_system.jsp

[16] The November 2011 ABACCUS report (pp. 19-21) provides an excellent review of the innovation emerging in the competitive electricity market place in both the residential and non-residential sectors. Innovation is the result of the opportunity, unavailable under monopoly-price regulation, for competitors to address the key reality identified in ABACCUS that "different people value things differently."

[17] In addition to providing a list of competitive suppliers with links and information about how customers can switch, the CTEnergyInfo website offers rate comparison pages for residential and small business customers http://www.ctenergyinfo.com/choose_entry.htm.

[18] Residential choice in Dayton Power & Light is comparatively small and near-zero in the two AEP utility areas.

[19] ABACCUS November 2011, p45.

[20] Illinois Commerce Commission http://www.pluginillinois.org/Suppliers.aspx.

[21] Illinois Commerce Commission http://www.icc.illinois.gov/ORMD/MunicipalAggregation.aspx.

[22] ABACCUS November 2011, p64. NewEnergy Ventures was the retail supplier serving an industrial customer.

[23] ABACCUS November 2011, p19-21.

[24] ABACCUS November 2011, p104.

[25] "Japan's utilities warned of shake-up: electricity users to get more choice as power shortages loom." *Financial Times*, January 20, 2012.

Note on Author

Philip R. O'Connor is President of PROactive Strategies Inc. and a former utility regulator, having served as Chairman of the Illinois Commerce Commission (1983-85). He was an early advocate of competitive market solutions in telecommunications, natural gas, electricity and power plant emission reductions. O'Connor has been appointed by five consecutive Illinois Governors to numerous positions in Illinois State Government including Director of Insurance and member of the State Board of Elections. He earned his doctorate in political science from Northwestern University and in 2007-8 served in the U.S. Embassy in Baghdad, Iraq as an advisor to the Iraqi Ministry of Electricity.