Response of the Pennsylvania Public Utility Commission To House Resolution 506

June 2008
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A. Introduction

The Pennsylvania House of Representatives passed House Resolution 506, effective Jan. 16, 2008, urging the Pennsylvania Public Utility Commission (and also the state Department of Environmental Protection) to “exercise due diligence on behalf of this Commonwealth’s energy consumers by identifying and evaluating measures taken in other states to manage the transition from electricity rate caps to no rate caps and minimize its impact upon the individual residential consumer, to make written suggestions on how certain laws may be changed to reduce the incidence of rate shock and the impact of rate shock and to submit the suggestions to the Chief Clerk for distribution among members of the House of Representatives.”

This report responds with the information requested by House Resolution 506 and includes the activities and actions taken by the Public Utility Commission (PUC or Commission) related to the transition to a fully competitive electricity market in Pennsylvania.

The Commonwealth’s move toward competitive retail electric markets did not take place in a vacuum. Competition in the national wholesale natural gas market had shown that competition could drive efficiencies and lower prices at the wholesale level. Other states, notably Texas and California, began to aggressively explore retail competition for their markets.

As competitive markets in the energy sector drew more and more interest across the country, sectors of Pennsylvania’s economy also began examining the possibility of competition for electricity generation. A combination of business taxes, workers’ compensation requirements and higher-than-average electric prices substantially affected Pennsylvania’s ability to compete with neighboring states for jobs and businesses. Large industrial customers had seen success in wholesale gas competition and began advocating for the ability to arrange similar transactions for electricity. Also, rate disparity was rampant throughout the Commonwealth. In 1995, Duquesne Light Company had some of the highest electric rates in the Commonwealth. Its neighboring utility, West Penn Power, had some of the lowest rates in the Commonwealth. Finally, it cannot be over-emphasized that, in 1995, Pennsylvania’s statewide average electric rates were well above the national average.

The Commonwealth’s exploration of competitive retail markets continued into 1996. California was well on its way to opening its competitive market. The operator of the transmission grid for Pennsylvania and the surrounding region, PJM Interconnection LLC (PJM), was finalizing the logistics of a competitive wholesale market. That effort included development of complex systems to schedule, deliver and account for a myriad of simultaneous transactions to “wheel” power across the regional grid while maintaining system reliability.
With the perception that something had to be done to manage Pennsylvania’s electric rates, with industrial customers aggressively seeking direct access to electricity generation, and with PJM building a wholesale market and systems that could form the backbone of a Pennsylvania retail market, a confluence of interests and events set the stage for retail competition. In time, those events and interests combined to convince Gov. Tom Ridge and the General Assembly that an electric competition or “restructuring” bill would be necessary to move the Commonwealth forward to keep pace with national markets and states competing with Pennsylvania for business.

1. The Electricity Generation Customer Choice and Competition Act

Adopted in December 1996, effective Jan. 1, 1997, the Electricity Generation Customer Choice and Competition Act (Customer Choice Act) was one of the most ambitious efforts in the country to move to retail electric competition. Based primarily on the legislative finding that “competitive market forces are more effective than economic regulation in controlling the cost of generating electricity,” the Customer Choice Act provided the basic ground rules under which competition would proceed in Pennsylvania -- 66 Pa. C.S. § 2802(5).

Under the Customer Choice Act, formerly vertically integrated utilities were required to “unbundle” their electric service into distribution, transmission and generation services -- 66 Pa. C.S. § 2804(3). Distribution and transmission (wires services) would continue to be regulated -- 66 Pa. C.S. § 2804(10). Generation services would be unregulated -- 66 Pa. C.S. § 2806(a). Pursuant to rules and regulations fashioned by the Public Utility Commission, customers would have direct access to electricity generation suppliers for their generation. Similar to the PJM model in the wholesale markets, utilities were required to provide open and non-discriminatory access to the generation market -- 66 Pa. C.S. § 2804(6).

In order to ensure that the transition to competitive markets was smooth, the Customer Choice Act provided that, for a period of time, rates would be capped at the levels which existed as of the effective date of the Customer Choice Act -- 66 Pa. C.S. § 2804(4). In litigated proceedings before the Public Utility Commission, the generation rate caps were extended for almost all utilities. The final rate caps which affect the majority of Pennsylvania customers will remain in place until Dec. 31, 2010. With some exceptions, the majority of Pennsylvania customers are paying the same generation rates today that they were paying 12 years ago, in 1996.

Another way to ease the transition to competitive markets was the requirement that, so long as a utility was collecting stranded costs, the utility must provide generation service to all customers who choose not to shop, who cannot find providers in the competitive market, or who were unable to continue service with a competitive electricity generation supplier -- 66 Pa. C.S. § 2807(e). This service is now known as default service. Default service plans must be approved by the Public Utility Commission. However, once the generation rate caps are removed, the default service provider is required to provide generation at “prevailing market prices” -- 66 Pa. C.S. § 2807(e)(3).
The Customer Choice Act also provided that utilities be made whole for investment in approved plant. Over the years, utilities invested in generation plants in order to provide service which met specific reliability standards. At the time the Customer Choice Act was passed, there was concern that some of that investment, which was recoverable in a regulated environment, would become “uneconomic.” That is, the rates for generation in the competitive market would not provide full recovery of costs which normally would have been approved for collection. Accordingly, those costs would be deemed “stranded.” The utilities were given the opportunity to establish what their stranded costs were and collect those costs over time -- 66 Pa. C.S. § 2808. For most of the utilities, collection of stranded costs would continue until rate caps were removed. Up until that time, the cost of generation for customers would include the cost of generation plus the stranded costs. Once the stranded cost collection was completed, that portion of the customer’s bill would be eliminated and only the actual cost of generation would be collected.

In addition to establishing a retail market, providing for stranded costs and default service, the Customer Choice Act mandated that universal service programs must be “appropriately funded” -- 66 Pa. C.S. § 2804(9). Also, reliability of the system was to be maintained at all times -- 66 Pa. C.S. § 2804(1). Finally, the Customer Choice Act provided that utilities had the option to “securitize” their stranded cost numbers -- 66 Pa. C.S. § 2812. To the extent that a utility securitized its stranded costs, that figure was not subject to any adjustment.

2. Current Status of Competition

Competition in Pennsylvania’s retail markets is stagnant with a few exceptions. Two territories where rate caps are now expired are Duquesne Light Service and Pennsylvania Power Company. In each of those territories, it can be seen that there has been in increase in shopping activity from January 2004 to January 2008. Another sector where competitive shopping has been fairly strong is in the green market where generation is branded as environmentally friendly. The following shopping statistics are taken from the Pennsylvania Consumer Advocate’s Web site, www.oca.state.pa.us:
### Percent of Customers Served By An Alternative Supplier As Of 1/1/2000

<table>
<thead>
<tr>
<th>Supplier</th>
<th>Residential</th>
<th>Commercial</th>
<th>Industrial</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Allegheny Power</td>
<td>1.3</td>
<td>6.3</td>
<td>32.9</td>
<td>1.9</td>
</tr>
<tr>
<td>Duquesne Light</td>
<td>22.2</td>
<td>17.51</td>
<td>17.0</td>
<td>21.7</td>
</tr>
<tr>
<td>GPU Energy</td>
<td>5.05</td>
<td>15.91</td>
<td>32.30</td>
<td>6.47</td>
</tr>
<tr>
<td>PECO Energy</td>
<td>14.94</td>
<td>25.78</td>
<td>58.34</td>
<td>16.09</td>
</tr>
<tr>
<td>Penn Power</td>
<td>6.0</td>
<td>10.6</td>
<td>36.7</td>
<td>6.6</td>
</tr>
<tr>
<td>PP&amp;L</td>
<td>2.3</td>
<td>12.7</td>
<td>10.7</td>
<td>3.6</td>
</tr>
<tr>
<td>UGI</td>
<td>4.2</td>
<td>2.8</td>
<td>–</td>
<td>4.0</td>
</tr>
</tbody>
</table>

### Percentage of Customers Served By An Alternative Supplier As Of 01-01-04

<table>
<thead>
<tr>
<th>Supplier</th>
<th>Residential</th>
<th>Commercial</th>
<th>Industrial</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Allegheny Power</td>
<td>0.1</td>
<td>0.1</td>
<td>0</td>
<td>0.1</td>
</tr>
<tr>
<td>Duquesne Light</td>
<td>24.9</td>
<td>20.5</td>
<td>38.9</td>
<td>24.4</td>
</tr>
<tr>
<td>MetEd/Penelec</td>
<td>0.2</td>
<td>0.1</td>
<td>1.4</td>
<td>0.2</td>
</tr>
<tr>
<td>PECO Energy*</td>
<td>20.4</td>
<td>39.8</td>
<td>4.3</td>
<td>22.2</td>
</tr>
<tr>
<td>Penn Power</td>
<td>0.3</td>
<td>0.1</td>
<td>0.0</td>
<td>0.3</td>
</tr>
<tr>
<td>PPL</td>
<td>0.1</td>
<td>1.0</td>
<td>1.8</td>
<td>0.3</td>
</tr>
<tr>
<td>UGI</td>
<td>0.1</td>
<td>0.0</td>
<td>-</td>
<td>0.1</td>
</tr>
</tbody>
</table>

*Includes 1.9% of PECO’s residential customers assigned to Competitive Discount Service (CDS) and 14.3% residential customers assigned to the Market Share Threshold Program (MST). Also includes 29.7% commercial customers assigned to the MST. Does not include 10.0% of former CDS residential customers now served by PECO on a CDS rate.

Totals may differ due to rounding.

### Percentage of Customers Served By An Alternative Supplier As Of 1/1/2008

<table>
<thead>
<tr>
<th>Supplier</th>
<th>Residential</th>
<th>Commercial</th>
<th>Industrial</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Allegheny Power</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Duquesne Light</td>
<td>22.5</td>
<td>17.1</td>
<td>47.1</td>
<td>22</td>
</tr>
<tr>
<td>MetEd/Penelec</td>
<td>0</td>
<td>0</td>
<td>0.1</td>
<td>0</td>
</tr>
<tr>
<td>PECO Energy</td>
<td>0.3</td>
<td>16.5</td>
<td>0.1</td>
<td>1.9</td>
</tr>
<tr>
<td>Penn Power</td>
<td>9.3</td>
<td>11.5</td>
<td>64.4</td>
<td>9.6</td>
</tr>
<tr>
<td>PPL</td>
<td>0</td>
<td>0</td>
<td>0.2</td>
<td>0</td>
</tr>
<tr>
<td>UGI</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

Totals may differ due to rounding.
When measured by the percentage of customers actually receiving competitive service, shopping has trended down from January 2000 to January 2008, with the exception of Duquesne Light Company. Duquesne Light has stayed fairly constant at approximately 21 percent. There are two basic reasons for the Duquesne Light experience. First, Duquesne Light had the highest rates as competition began so that competitive suppliers were able to compete against those capped rates in the early stages of the transition. Second, Duquesne Light’s rate caps have expired. Accordingly, Duquesne Light Company’s current default service rates (the “price to compare”) are based on prevailing market prices and afford competitive suppliers a better opportunity to compete in that service territory.¹

3. Factors Affecting Electric Pricing

While most of Pennsylvania’s electric customers are receiving generation under rates capped at 1996 levels, other factors have been at work to affect the cost of that generation. Certain basic cost inputs for electric generation have risen dramatically. Coal makes up approximately 36 percent of PJM’s fuel mix. Natural gas makes up about 14 percent of that fuel mix. Since 1995, one year before Pennsylvania’s rate caps became effective, the price of coal has risen approximately 55 percent. The price of natural gas has risen 140 percent.²

In addition to the cost inputs of fuel for generation, the costs to construct new generation plants, transmission facilities and distribution facilities, as well as costs to upgrade and maintain existing facilities, have also risen dramatically. These increased costs include raw materials and project management. One study indicates that the price trends in steam generation, transmission and distribution infrastructure costs rose by 25 percent to 35 percent from January 2004 to January 2007. It should be noted that costs for gas turbines increased by 17 percent during 2006 alone. Additional increases due to the costs of environmental controls are also anticipated.³

The electric wholesale market also directly affects retail prices available in Pennsylvania’s markets. At the present time, PJM’s wholesale spot market operates on a single clearing price mechanism. Generators bid supply into the market. The bidding continues until the supply bid matches the forecasted demand. The final supply bid which matches demand sets the price for the entire supply. Since the bidding usually escalates in price, what actually occurs is that the highest bid sets the price for supply.⁴ At this time, the highest cost generation in PJM is natural gas fired. That type of generation sets the wholesale price of electricity approximately 25 percent of the time.

Recall that natural gas prices have risen approximately 140 percent since Pennsylvania’s rate caps began. The price of coal has also risen substantially. Coal-fired generation sets the wholesale price approximately 70 percent of the time.\(^5\)

It must be noted that a second facet to the wholesale market involves PJM’s Reliability Pricing Model (RPM), which is having an impact on capacity prices in PJM. Those capacity prices are, in turn, impacting the bidding for default service supply in Pennsylvania’s default service programs. Data from PJM reflect the following clearing prices (on a per-MW-day basis) for capacity for the indicated planning years: $40.80 (2007); $111.92 (2008); $102.04 (2009); $174.29 (2010); and $110 (2011). Even with the substantial drop in price between the planning years 2010 and 2011, it can be seen that there is an extremely large increase from the 2007 planning year, $40.80 to $110. This substantial increase will be reflected in default service supply bids.

You will note that the latest PJM RPM auction results see prices drop. This appears mainly to be due to Duquesne Light’s exit from PJM. If Duquesne had not exited PJM, adding its 1,511 MW back in would have resulted in a clearing price not much different than last year’s $174.29 clearing price. Minor additional factors include an increase in offered demand response and a very small increase in internal PJM offered capacity. The greatest source of the offered capacity increase comes from imports from other regions. Most of the increase in offered capacity comes from outside PJM, or from customer demand response. This auction could be touted as proof that RPM is working, but the actual data supplied does not support that conclusion.

A third basic element, demand for electricity, also continues to grow. The following charts indicate the growth in demand for electricity in PJM for residential, commercial and industrial customers:

**Increased Use of Electricity in PA - Residential**

<table>
<thead>
<tr>
<th>Year</th>
<th>GWH Sales</th>
<th>No. of Customers</th>
<th>Average KWH/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>1996</td>
<td>43,645</td>
<td>4,860,128</td>
<td>8,999</td>
</tr>
<tr>
<td>1997</td>
<td>42,785</td>
<td>4,884,572</td>
<td>8,759</td>
</tr>
<tr>
<td>1998</td>
<td>42,923</td>
<td>4,908,255</td>
<td>8,745</td>
</tr>
<tr>
<td>1999</td>
<td>44,126</td>
<td>4,956,852</td>
<td>8,902</td>
</tr>
<tr>
<td>2000</td>
<td>45,008</td>
<td>4,933,000</td>
<td>9,124</td>
</tr>
<tr>
<td>2001</td>
<td>46,030</td>
<td>5,021,433</td>
<td>9,167</td>
</tr>
<tr>
<td>2002</td>
<td>48,730</td>
<td>5,048,925</td>
<td>9,652</td>
</tr>
<tr>
<td>2003</td>
<td>49,651</td>
<td>5,082,234</td>
<td>9,770</td>
</tr>
<tr>
<td>2004</td>
<td>50,663</td>
<td>5,121,901</td>
<td>9,892</td>
</tr>
<tr>
<td>2005</td>
<td>53,661</td>
<td>5,154,728</td>
<td>10,410</td>
</tr>
<tr>
<td>2006</td>
<td>51,790</td>
<td>5,190,697</td>
<td>9,977</td>
</tr>
</tbody>
</table>

Based on Energy Information Administration (EIA) data. Sales increased at an annual average of 2.55%. Average usage increased at an annual average of 1.7%. The number of customers increased at an annual average of 0.7%.

**Increased Use of Electricity in PA - Commercial**

<table>
<thead>
<tr>
<th>Year</th>
<th>GWH Sales</th>
<th>No. of Customers</th>
<th>Average KWH/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>2001</td>
<td>40,552</td>
<td>615,588</td>
<td>65,876</td>
</tr>
<tr>
<td>2002</td>
<td>42,631</td>
<td>624,663</td>
<td>68,248</td>
</tr>
<tr>
<td>2003</td>
<td>43,217</td>
<td>637,255</td>
<td>67,819</td>
</tr>
<tr>
<td>2004</td>
<td>44,355</td>
<td>646,781</td>
<td>68,579</td>
</tr>
<tr>
<td>2005</td>
<td>45,781</td>
<td>655,717</td>
<td>69,819</td>
</tr>
<tr>
<td>2006</td>
<td>45,623</td>
<td>665,763</td>
<td>68,528</td>
</tr>
</tbody>
</table>

Based on Energy Information Administration (EIA) data. Commercial sales increased at an annual average of 2.89%. Average usage increased at an annual average of 1.07%. The number of customers increased at an annual average of 1.6%.
Use of Electricity in PA - Industrial

<table>
<thead>
<tr>
<th>Year</th>
<th>GWH Sales</th>
<th>No. of Customers</th>
<th>Average GWH/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>2001</td>
<td>47,383</td>
<td>28,616</td>
<td>1,655</td>
</tr>
<tr>
<td>2002</td>
<td>47,089</td>
<td>28,414</td>
<td>1,657</td>
</tr>
<tr>
<td>2003</td>
<td>46,773</td>
<td>28,355</td>
<td>1,649</td>
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<tr>
<td>2004</td>
<td>47,659</td>
<td>28,350</td>
<td>1,681</td>
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<tr>
<td>2005</td>
<td>47,950</td>
<td>28,326</td>
<td>1,692</td>
</tr>
<tr>
<td>2006</td>
<td>47,920</td>
<td>28,727</td>
<td>1,694</td>
</tr>
</tbody>
</table>

Based on Energy Information Administration (EIA) data. Industrial sales increased at an annual average of 0.15%. Average usage increased at an annual average of 0.36%. The number of customers decreased at an annual average of 0.2%.

Cost inputs, demand and the wholesale market pricing mechanism all contribute to increase wholesale costs which will affect retail prices for Pennsylvania consumers.
4. Increases in Other Prices

The following chart provides information on price increases for various commodities, including natural gas, coal and the average price for electricity in Pennsylvania. This chart provides some perspective on the pressure which can be expected on Pennsylvania’s electricity rate caps.

Electric Prices Compared to Inflation, Other Commodities

5. Benefits of Competition

It must be stressed that, as long as Pennsylvania continues to operate under retail rate caps, the transition to competition is ongoing. Accordingly, while Pennsylvania’s retail market has been open since 1998, it is not a mature market as envisioned by the Customer Choice Act. There are simply not enough competitive electricity generation suppliers able to operate within the established rate caps to produce the pricing benefits and technological advances one would expect from a robust competitive market. However, there have been some successes.

The Customer Choice Act itself produced one of the first significant benefits when it unbundled utility services and moved generation into the unregulated side of the business. By moving generation out of regulated services, the Customer Choice Act put the risk of uneconomic plants, construction cost over-runs and inefficient operations on the generation plant owners, not ratepayers. Pennsylvania ratepayers will not be subject to rate shock when a new nuclear plant becomes operational or produces substantial construction cost over-runs.
Another real benefit has been that rates adjusted for inflation have actually been declining. Pennsylvania consumers are paying 12 percent less for electricity than in 1996 when rates are adjusted for inflation. The U.S. Department of Energy (DOE) indicates that Pennsylvania’s average electricity rate was 3 percent below the national average in 1997, but was 15 percent above the national average in 1991.

Rate caps have expired in the Duquesne Light Company and Pennsylvania Power Company areas. Even with the expiration of rate caps, electricity rates in constant dollars were lower in 2007 than they were in 1991 in those areas. Compared to 1991, residential rates, when adjusted for inflation, are down 38 percent in the Duquesne Light Company service territory and down 11 percent in the Pennsylvania Power Company service territory area.

When the risk of inefficiency is taken from ratepayers and placed on generators, plant efficiency rises. In the PJM market, it has been estimated that generation plant efficiency has increased to such an extent that Pennsylvania ratepayers have realized approximately $120 million per year in savings. In addition, more efficient plant operation means that less generating plants will be needed to serve the same demand.

Pennsylvania’s competitive markets have also seen a substantial number of “green” energy products introduced that would have been unlikely before the Customer Choice Act. The Alternative Energy Portfolio Supply Act of 2005, 75 P.S. §§ 1648.1, et seq., provided tremendous impetus to the use of alternative fuels to produce Pennsylvania’s generation. Even before that Act, the competitive marketplace was responding to customer interest in alternative energy. For example, in November 2004, PECO Energy announced that it had enrolled more than 9,000 homes in its wind energy program.

As noted above, Pennsylvania’s retail competitive market is still in transition. Accordingly, the full panoply of innovative products and techniques which a fully functioning competitive market can provide is still on the horizon. However, even at this stage, substantial efforts are being put forth in areas such as advanced metering and customer control to advance demand response and energy efficiency programs far beyond those in existence today. A great deal of credit for those initiatives lies with the

8 PennFuture, It Just Isn’t So: Part 3 __3, Vol. 9, No. 2 at 3 (February 15, 2007), op cit..
AEPS Act of 2005 and its amendments. However, it is Pennsylvania’s retail competitive marketplace that will provide a platform for companies to offer those types of services.

6. Challenges Presented by Competition

First and foremost, basic pricing assumptions that existed at the time the Customer Choice Act was passed are now outdated. Quite simply, the Customer Choice Act’s rate caps were put in place at a time when natural gas prices were on the order of $2.25 per MCF. Today, natural gas prices are extremely volatile, but the average well-head price for natural gas for April 2008 is estimated at $8.93 per MCF. Coal also has increased dramatically. Those generation cost inputs mean that it is extremely difficult, if not impossible, for competitive electricity generation suppliers to offer service below existing rate caps and remain profitable. Retail rates over the past 10 years have increased on average 31 percent in both restructured and traditionally regulated states. Pennsylvania’s rate caps have kept retail rates from rising to that extent, but it appears likely that some increase will be necessary.

Second, default service program design must be carefully managed to provide reasonable prices to consumers without destroying the competitive market. We have seen that rate caps that are artificially low, in some instances below the wholesale price, will prevent any competitive entry. Similarly, a default service program design that produces the lowest possible prices will inhibit competitors from entering the market. Balancing the interests of default service customers for reasonable prices with the need for a robust competitive market will be one of the Commission’s more difficult tasks in the coming years. As the Commission grapples with this task, it is important to note that default service is an alternative to the competitive market. The current state of the law indicates that a vibrant and robust competitive market should be the primary focus going forward.

The third major challenge will be customer education. To date, customer education has been focused on teaching consumers about competition, the market place and how to shop. The Commission plans to emphasize the price of energy, conservation and efficiency, and inform consumers about the expiration of rate caps, and how to prepare for that event. The Commission will have to continue basic education on electricity markets and shopping, although those topics will take on a heightened urgency as the rate caps expire.

Several challenges have confronted the Commission and market participants over the past decade and will continue to be significant issues. Some of these issues include reliability; utility/competitor interactions; utility affiliate transactions; federal

11 MCF is a unit of measure for natural gas. One MCF = one-thousand cubic feet of natural gas.
12 Price information provided by the U.S. Energy Information Administration.
13 Pfeifenberger, Basheda and Schumacher, Restructuring Revisited, Public Utilities Fortnightly, June 2007 at 65.
wholesale pricing models; environmental requirements; transmission constraints; and
generation adequacy. These issues will continue to require Commission action to
ensure that Pennsylvania’s electricity retail market will move forward in positive ways for
Pennsylvania’s consumers.

B. Activities of Other States

Commission staff researched activities and experiences of other key states:
California, Delaware, Illinois, Indiana, Maryland, New Jersey, New York, Ohio, Texas
and Virginia.

1. Status of Deregulation in Other States

Overview of the background of deregulation, resulting rate increases, price
mitigation attempts, and status of competitive markets in other states.

California
Background: California began deregulation in 1996, placing rate caps on retail rates.
Electric companies began paying spot market prices in 1998. In May 2000, spot market
prices began to rise considerably. A variety of factors, including increasing prices, led
to the 2000-01 energy crises.

Rate Increase: Significant increases were experienced statewide in 2000-01 due to
spot market prices and market manipulation by certain parties such as Enron.

Price Mitigation: In 2001, legislation was passed that authorized the California
Department of Water and Resources (CDWR) to buy and sell power. This occurred as
a result of the Pacific Gas & Electric bankruptcy and the public bailout of Southern
California Edison. These companies did not resume procuring power until Jan. 1, 2003.
By July 2001, spot prices were back down at pre-crisis levels. According to FERC,
prices have been stable since then. Existing shopping customers can continue to
renew competitive market contracts with existing or new competitive suppliers. Non-
shopping customers must remain with the utility until otherwise permitted to switch by
the Commission. In 2007, the CA PUC authorized it first community choice aggregation
program, enabling a community to purchase energy. Other programs under
consideration in the state would allow customers to purchase power from marketers and
independent power producers.

Competitive Markets: Not developed.
Delaware
Background: In 1999, Delaware enacted a retail choice program. Generation was deregulated while distribution remained a regulated monopoly. Similar to Pennsylvania, customers were free to choose their own generation supplier. As part of this, there was a phase-in program from October 1999 to April 2001. Residential customers were slated to receive a 7.5 percent discount.

Rate Increase: Residential customers of Delmarva Power Co. saw their electric bills increase by an average of 59 percent on May 1, 2006, when rate caps expired.

Price Mitigation: As a result of the increase in rates, the state’s General Assembly passed legislation which enrolled all of Delmarva’s customers in a plan that would spread higher rates out through 2009. This plan was an “opt-out” program, and about 60 percent of customers elected not to participate in the rate deferral program.

Competitive Markets: Three of 29 certified suppliers currently offer service to residential customers.

Illinois
Background: Deregulation began in 1997. Much like Pennsylvania, electric rates were frozen for 10 years through the end of 2006.

Rate Increase: There was a 40 percent residential rate increase, on average, when the rate freeze ended.

Price Mitigation: In response to the rate increase, electric distribution companies agreed to extend residential rate caps for an additional two years and offer $1 billion in rebates to consumers. The Illinois General Assembly passed PA 95-0481, granting $1 billion in rate relief, with a minimum $85 rebate per customer, through 2009 for select residential and non-residential customers of Commonwealth Edison and Ameren. Rebates were a one-time occurrence for the benefit of those customers who were encouraged by electric companies to build all-electric homes. The legislation also created the Illinois Power Agency to purchase wholesale power to serve utility customers beginning in 2009.

Competitive Markets: Market is characterized by a lack of suppliers.

Indiana
Background: The Indiana electric industry is not currently deregulated.

Maryland
Rate Increase: Residential customers of Baltimore Gas & Electric saw their electric bills increase by an average of 72 percent on July 1, 2006. Their bills are projected to increase another 5.5 percent in June 2008.

Price Mitigation: Legislation has been introduced that would re-regulate the electric industry and return stranded costs collected to ratepayers. Maryland also had an opt-in rate deferral program and is holding hearings on energy efficiency and demand side management programs. Maryland has already implemented some of these programs.

Competitive Markets: Between four and 10 active suppliers for residential customers, 36-50 active suppliers for commercial customers and 36-47 active suppliers for industrials.\textsuperscript{14}

\textbf{New Jersey}

Background: Deregulation began Aug. 1, 1999. There was no rate phase-in, but 100 percent immediate competition.

Rate Increase: In 2006, New Jersey’s fifth electric auction for basic generation service resulted in prices that were more than 50 percent higher than 2005’s auction (Source: EIA).

Price Mitigation: Regulators use a “dampening approach” to deal with volatility by averaging in increases over three years

Competitive Markets: There are relatively few residential suppliers with no residential switching of suppliers. Between eight and 22 active commercial suppliers and eight and 28 active industrial suppliers.\textsuperscript{15}

\textbf{New York}

Background: Electric deregulation began in 1996.

Rate Increase: Real (inflation-adjusted) prices for typical residential retail customers dropped by an average of 16 percent between 1996 and 2004.

Price Mitigation: The plan was phased-in based on separate rate/restructuring settlements with each electric utility.

Competitive Markets: There are 73 licensed suppliers with at least seven residential suppliers in each of the majority utility’s service territories, and 20-37 suppliers for the non-residential market.\textsuperscript{16}

\textsuperscript{14} MD electricity supplier Web site, accessed May 5, 2008, http://webapp.psc.state.md.us/Intranet/SupplierInfo/searchSupplier_E.cfm
Ohio
Background: Rate caps are set to expire at the end of 2008.

Rate Increase: There was a 40 percent residential rate increase, on average.

Price Mitigation: Ohio passed new energy legislation which the Governor signed on May 1, 2008. A highlight of the legislation is an Economic Security Plan which will require the development of essentially cost-based rates by all electric utilities. These rates will be compared to market-based rates. If the cost-based rate is less than the market rate, then that price must be billed to customers.

Competitive Markets: There are relatively few suppliers. AEP and DPL have zero percent of their residential customers switching to alternative suppliers.

Texas
Background: Deregulation effective Jan. 1, 2002.

Rate Increase: Deregulated customers pay a premium of 29 percent above the average regulated rate of 10 cents per kwh.

Price Mitigation: Partial statewide choice was delayed in markets that are determined to have inadequate competition. Beginning Jan. 1, 2006, the price to compare has been eliminated from the electric choice program. Full competition among the 50 retail suppliers serving the state is under way.

Competitive Markets: While prices to customers increased 43 percent from 2002 to 2004, input or production prices rose even more, suggesting that competition is preventing the full cost of generation increases from being passed onto consumers.

Virginia
Background: The state passed an electric restructuring law in 1998.

Rate Increase: Prices were capped from 2002-2007.

Price Mitigation: In 2004, the Virginia General Assembly extended the rate-cap expiration from 2007 to 2010. In 2007, the rate caps were rolled back to expire in 2008. Re-regulation of electric utilities became law on July 7, 2007, with a return to full costs of service regulation. The legislation included incentives for utilities to build new generation and to invest in renewable energy sources and demand side management programs.

Competitive Markets: Not applicable.

2. **Consumer Education**

Consumer education is an important factor in studying how other states transitioned “from rate caps to no rate caps,” as described in House Resolution 506. Were a state’s consumers prepared for higher electricity prices? Did they know the increases were coming? Did they know what their options were for personally controlling or mitigating the impact of the increases through energy conservation, available assistance programs, and alternative electricity providers?


Following is a report on consumer-education activities of these and other states as compiled by PUC staff and consumer-education stakeholders.

**California**

Program Highlights:
- Established a price-to-compare Web site for electric customers. The site gives consumers the ability to compare their current utility supplier’s rates with rates of competitors.
- Established an e-mail system to give citizens notifications of potential energy shortages during the hot weather season.
- Established a Web site that highlights energy efficiency rebates and services for appliances, lighting, and heating and cooling. The information is regionalized by zip code.
- Developed consumer materials (brochures, fact sheets, etc.) for use at consumer-education events and for downloading from the Flex Your Power Web site. The materials focus on energy conservation, consumer choice, Energy Star® products and programs for low-income consumers.
- Developed extensive statewide radio and television campaign to highlight electric choice as part of the Flex Your Power program.
- Produced podcasts, electronic newsletters and Internet blogs related to choice.
- Held events across the state to highlight the Flex Your Power program.
- Created Flex Alert, a special Web site to recruit and train community-based organizations and businesses that share information about electric choice with the people in their communities, employees or customers.
- Austin Energy partnered with Home Performance with Energy Star® program.

Funding:
- Research shows that, from June 2002 through June 2007, California spent approximately $18.1 million in media outreach.
Timing:
Research indicates that California began its program in early 2001. The program is ongoing.

Web Link(s):

Flex Your Power, http://www.fypower.org/

Flex your Power TV Ads, http://www.fypower.org/res/ads/


**Delaware**

Program Highlights:
Delaware is a Partner with the Home Performance with Energy Star® program. The Delaware Million Solar Roofs Coalition was created to support a federal initiative to promote residential use of solar technology. Delaware participates in the Save Energy Now initiative of the U.S. Department of Energy’s Industrial Technologies Program, which focuses on helping manufacturers reduce energy usage and cut costs.

Funding:
On May 2, 2006, Gov. Minner signed SB 281 and appropriated $8 million in funds to the Delaware Department of Natural Resources and Environmental Control for Energy Efficiency Program.

Web Link(s):

**Illinois**

Program Highlights:
Electric distribution companies (EDCs) coordinate all consumer outreach with input from the Commission. The Illinois Commerce Commission convened several stakeholder group meetings to outline the issues. The state saw increases of 200-300 percent when rate caps were removed. State government ordered EDCs to offer discounted rates and credits for consumers who were encouraged to switch to all electric houses in the 1990s. Illinois is working to bring choice to residential consumers.

Web Link(s):
Indiana

Program Highlights:
The state is not going through restructuring.
Electric utility companies handle the bulk of consumer education.
Ratepayers are assessed for utilities' energy efficiency budgets.

Web Link(s):
Indiana Utility Regulatory Commission, http://www.in.gov/iurc/

Maryland

Program Highlights:
Developed demand side response and energy efficiency programs, and each company promoted the programs with its customers.
Provided information to customers on efficiency appliances, ecologically friendly building practices and affordable home improvements.
 advertised via bill inserts, trade shows and community events.
Developed Watt Watchers program on efficiency for schools.
Developed energy auditing software to enable customers to see how they can alter energy usage.
Conducted energy know-how campaign -- residential heating, ventilation and air conditioning (HVAC) efficiency program. The program involves education of HVAC efficiencies, proper training on system installation and incentives (rebates on customer bills), and installation of high-efficiency units up to five tons, as determined by a third-party vendor.
Partnered with Home Performance with Energy Star® program.

Funding:
Media outreach -- approximately $100,000 budgeted for 2007-08 FY.
Software development -- approximately $1 million.
Incentives -- $2 million in incentives and $500,000 in implementation costs.
Pepco's Energy Awareness campaign -- $1.86 million.
Delmarva Power and Light's Energy Awareness campaign -- $1.23 million.

Web Link(s):
Maryland Home Performance with Energy Star®,
http://www.mdhomeperformance.org/
Delmarva Power, http://www.delmarva.com/home/
Michigan

Program Highlights:
Regulators approved a $13 million low-income and energy efficiency grant to be administered by the Michigan Department of Human Services and other community-based organizations. About $9 million of the funding was earmarked for energy efficient upgrades for low-income consumers with $4 million directed to consumer education.

Web Link(s):

New Jersey

Program Highlights:
Conducts education regarding conservation and energy efficiency. Contracts with a company that provides educators who work in the field.

Funding:
New Jersey has a budget of $391 million for conservation/efficiency consumer education and energy programs for the next fiscal year. Some of these funds were carried over from the previous fiscal year.

Web Link(s):

New York

Program Highlights:
Established a price-to-compare Web site for electric and natural gas customers. The site gives consumers the ability to compare their current utility supplier’s rates with rates of competitors. Developed consumer materials (brochures, fact sheets) for use at consumer-education events and for downloading from the New York Public Service Commission’s Web site. The materials focus on energy conservation, consumer choice, Energy Star® products and programs for low-income consumers. Utilized statewide radio and television spots in support of the Power to Choose campaign. Established the Energy Smart Students Program, which offers curricula and hands-on applications-based instructional support for classroom lessons in energy and energy efficiency. Partnered with Home Performance with Energy Star® program.

Funding:
Research shows that, from June 2002 through June 2007, New York spent approximately $1.24 million in media outreach. The New York State Energy Research and Development Authority (NYSERDA) has allocated $31 million for general awareness and marketing activities for 1998-2011. So far, $18 million has been spent.

Timing:
New York’s campaign began in early 2002 and is currently ongoing.

Web Link(s):


Ohio

Program Highlights:
The 2000-05 Choice Campaign was completed in 2005. The Ohio Public Utilities Commission is not conducting significant conservation-related consumer education. No money was approved in the May 1, 2008, energy legislation for consumer education. Required Electric Security Plans are similar in nature to PUC rate stabilization proceedings. Increases would be spread out over a longer period. By the end of June, the Commission anticipates launching a Web site educating the public about its current proceedings, the impacts of rate cap removal, and the Electric Security Plans. The Commission may have education efforts in the future, but no coordinated statewide education campaign is planned at this time.

Web Link(s):

Texas

Program Highlights:
Established a price-to-compare Web site for electric customers. The site gives consumers the ability to compare their current utility supplier’s rates with rates of competitors. Developed consumer materials (brochures, fact sheets) for use at consumer-education events and for downloading from the Texas Public Utility Commission’s Web site. The materials focus on energy conservation, consumer choice, Energy Star® products and programs for low-income consumers.
Implemented a statewide radio and television campaign to highlight the electric choice program.
Issued video news releases and other materials that highlighted the differences between Texas and California.
Held events across the state to highlight the electric choice program.
Established the consumer call center to handle questions related to electric choice (1-866-PWR-4TEX).
Created “Power Partners,” a special Web site to recruit and train community-based organizations and businesses that share information about electric choice with the people in their communities.
Partnered with Home Performance with Energy Star® program.

Funding:
Research shows that, from June 2002 through June 2007, Texas spent approximately $1.1 million in media outreach.

Timing:
Research indicates that the program began in early 2002 and is ongoing.

Web Link(s):
Texas Power to Choose, http://www.powertochoose.org/

**Virginia**

Program Highlights:
Recently enacted legislation restoring modified regulation of electric rates, effective Jan. 1, 2009.
No consumer education has been utilized.

Web Link(s):

**3. DSR/Energy Efficiency**

An overview of state energy efficiency, conservation and smart meter policies follows.

**California**

A California Public Utility Commission (CPUC) October 2007 decision, D.07-09-043, established a risk/reward incentive mechanism to encourage the utilities to invest in energy efficiency. The mechanism enables the utilities to earn rewards on energy
efficiency investments in amounts comparable to what they would otherwise earn on the supply side. That decision established a minimum performance standard for the utilities, under which incentive earnings begin to accrue only if the utility energy efficiency portfolio achieves at least 85 percent of the CPUC's goals. The utilities were allowed to receive interim incentive payments based on progress toward achievement of the goals, but these payments were subject to repayment if an after-the-fact review indicated that the minimum performance standards were not attained.

From the 2008 Energy Action Plan Update:

Demand Response section (Page 11): “We also should be moving toward more time-differentiated default rates for larger consumers, with the ability of those customers to opt out of these types of rates if they are willing to pay a higher flat rate (essentially a slight premium for the insurance of predictability in their tariffs).”

“Seek legislative authorization for time-varying pricing for residential consumers” (Page 14).

“Implement dynamic pricing rate design reform for all types of consumers” (Page 14).

**Delaware**

The legislature enacted a law creating a “Sustainable Energy Utility” (SEU) to coordinate and promote sustainable energy and energy efficiency (EE). This public/private partnership uses public funding sources and consumer savings to fund the program and uses “Special Purpose Bonds,” not increased electric rates. The program uses a competitively selected implementation contractor to deliver services and features end-user shared savings agreements with participating consumers. The SEU pays consumers the difference between regular efficiency and high efficiency appliances. The consumer pays back 33 percent of estimated savings for three to five years. The Delaware Energy Office (DEO) administers federal grants to states for EE programs. All ratepayers also pay increased rates to pay for DEO EE programs. The Energy Office promotes EE/conservation on its Web site. Smart meters are not required.

**Maryland**

In June 2006, the General Assembly passed legislation limiting rate increases to 15 percent, with a deferred amount paid over 10 years with interest. Maryland is examining re-regulation, and requiring utilities to increase energy savings targets by 15 percent per capita by 2015 through compact fluorescent lights (CFLs), rebates for replacement appliances, more transmission lines, more coal and nuclear plants, the lease of peak load plants, the solicitation of bids for cost-effective energy efficiency programs, and bilateral contracts with wholesale electricity suppliers.
New Jersey

Customers could have received $50-$75 rebates on Energy Star® washing machines through December 2007. The electric competition law allows for government energy aggregation programs at the municipal or county level. The February 2008 electricity auction resulted in overall bill increases from 10.5 percent to 17.3 percent.

New York

All customers pay increased electric rates for a Systems Benefit Charge, which funds the New York State Energy Research and Development Authority (NYSERDA). NYSERDA administers EE RFP (request for proposal) programs available through competitive procurement to non-utility EE providers. Utilities also administer their own EE programs and can increase all customer rates. NYSERDA provides energy saving conservation tips on its Web site, which includes information on CFLs; the Energy Star® Pledge (customers commit to purchasing Energy Star® products); Energy Star® Pledge Driver (organizations post info on their respective Web sites); power management; energy efficient holiday lighting; and where to find retailers. Smart meters are required only for largest customers in the state. Utilities submit plans.

Ohio

Utilities provide EE programs and are allowed to increase all customer rates. Smart meters are not required.

Texas

Texas legislature mandated that at least 10 percent of the EDCs’ annual growth in electricity demand be met through energy efficiency programs each year. The PUC established procedures for meeting the legislative mandate. Customers are given a variety of energy efficiency alternatives.

C. Commission Activities

The Pennsylvania Public Utility Commission has focused on preparing for the transition from capped rates to competitive rates for several years.

Price Mitigation Order

The Commission initiated a proceeding in early 2006 to consider policy tools available to mitigate electric price increases that may occur with the expiration of generation rate caps.

The Commission observed that, as generation rate caps had begun expiring in Pennsylvania and neighboring states in 2005 and 2006, retail customers had been subject to large rate increases. Accordingly, the Commission initiated an investigation on May 19, 2006, to consider ways to mitigate the impact and size of potential price increases. As part of this investigation, an en banc hearing was held on June 22, 2006. There were 39 participants who filed comments and reply comments. Issues for study included energy efficiency, conservation, demand side response, consumer education,
default service, reduction of peak demand, interaction between the retail and wholesale market, low-income customer assistance, and ways to minimize the abruptness of price increases. Comments and reply comments were solicited on these issues, and were posted to the Commission’s Web site.

With a process that culminated with our Final Order (Docket No. M-00061957), entered May 17, 2007, the Commission began to address expiring rate caps earlier than counterparts in other states. The Commission’s Order said the PUC would:

- Convene the Statewide Consumer-Education Stakeholders Group, which has met regularly since June 2007 to develop a proposed statewide campaign;
- Review and approve electric distribution company consumer-education plans, targeted to each service territory, which were to be filed by Dec. 31, 2007;
- Consider proposals to avoid large, abrupt retail electric rates on a case-by-case basis;
- Initiate a rulemaking process to modify our Customer Assistance Programs policy statement and regulations to address funding levels and cost recovery;
- Actively participate in the Universal Service Task Force and the Low Income Home Energy Assistance Program Advisory Committee to secure state funding for low-income energy customers;
- Address specific requests for Low Income Usage Reduction Program funding increases when opportunities arise; and
- Continue to actively participate in federal and regional proceedings that impact electricity prices.

**Default Service Rulemaking and Policy Statement**

The Electricity Generation Customer Choice and Competition Act requires the Commission to promulgate regulations governing an EDC’s obligation to serve retail customers after the conclusion of its restructuring transition period -- 66 Pa.C.S. § 2807(e)(2). This duty is often referred to as the provider of last resort (POLR) obligation. As the Act makes clear, the purpose of this obligation is to address the scope of retail electric service or default service that must be provided to customers who either have not chosen an alternative electric generation supplier or who contracted for electric energy that was not delivered. That obligation includes the connection of customers, the delivery of electric energy and the production or acquisition of electric energy for customers.

While the Act affords the Commission substantial latitude in developing the rules that govern this obligation, it clearly sets forth basic principles that must be followed by the Commission. First, the Act establishes that after the transition period electric consumers will continue to receive generation service from the EDC or a Commission-approved provider of last resort if either they do not choose an alternative electric generation supplier or they contract with an EGS for electric energy that is not delivered. Second, EDCs or Commission-approved providers of last resort are obligated to “acquire
electric energy at prevailing market prices.” Third, the EDC or Commission-approved POLR must be permitted to “recover fully all reasonable costs.”

The Commission’s Default Service Regulations (52 Pa. Code Chapters 54 and 57) and the accompanying Policy Statement (52 Pa. Code §§ 69.1801 et seq.) became effective upon their publication in the Sept. 15, 2007, Pennsylvania Bulletin (37 Pa.B. 4996). The regulations and policy statement represent a balanced approach to acquiring reasonable priced generation supply in a manner that balances the interest of all stakeholders, while meeting the requirements of the 1996 electric competition law.

The policy statement contains guidelines for the default service providers in the areas of procurement, rate design and cost recovery. The Commission recognized that some elements of the default service rules should be addressed in a policy statement rather than a rulemaking, because changes in markets and technology may result in an approach that is too narrowly tailored or too unresponsive to serve the state’s interests.

The law requires electric distribution companies, or a Commission-approved alternative supplier, to provide default electric generation service to customers who have not selected an alternative electric generation supplier. Some of the energy bills being considered at the special session will require changes to the Commission’s default service regulations and policy statement.

The policy statement also establishes a Retail Markets Working Group to develop policy recommendations, which are aimed at removing barriers to retail market development including rate-ready billing, customer referral programs, uniform statewide supplier tariffs and a retail choice ombudsman at both the Commission and electric distribution companies.

The regulations address:
- Competitive safeguards;
- Program terms and conditions of service;
- Procurement and implementation plans;
- Standards for transferring customer accounts;
- Rate design including the “price to compare”; and
- Recovery of costs.

The policy statement:
- Addresses retail market issues;
- Recommends that default service providers give customers the option to defer paying some portion of a rate increase for a period of time under certain conditions;
- Addresses interim price adjustments and cost reconciliation;
- Allows default service providers to craft an approach for electric generation supply procurement that is best suited to its own territory; and
- Includes an array of guidelines intended to improve competitive solicitation processes.
DSR Report

Demand side response (DSR) programs give consumers incentives to reduce or shift consumption of electricity at times of peak demand. DSR may therefore allow customers to realize lower electric bills and may foster system reliability.

The Commission initiated an investigation in late 2006 to examine energy efficiency, conservation and DSR. The Commission specifically sought recommendations as to reasonable cost-effective programs that can be implemented to help retail electric customers conserve energy or use it more efficiently. Besides programs, areas of inquiry include advanced metering infrastructure, consumer education and ratemaking mechanisms, such as revenue decoupling. To facilitate the investigation, the Commission reconvened the Demand Side Response Working Group (DSR).

The Report on Conservation, Energy Efficiency, Demand Side Response, and Advance Metering Infrastructure prepared by the DSR Working Group was released on June 6, 2007 (Docket M-00061984). It is available at the following link: http://www.puc.state.pa.us/electric/PDF/DSR/DSRWG_Report060607.pdf.

The Commission has postponed action on this report pending the outcome of the special legislative session on energy.

The DSR Working Group was originally formed in January 2001, following a roundtable discussion in November 2000, at which time participants overwhelmingly supported DSR as a way to enhance reliability and economic efficiency of the wholesale market and emphasized the link between healthy wholesale and retail markets. The initial focus of that group was on programs targeting medium to large commercial and industrial customers, with pilots for residential and small business customers.

In December 2002, the Commission presided over an en banc hearing to consider next steps. Testimony provided at the hearing supported continuation of the working group and expansion of the programs. Following that hearing, the group focused on giving more residential and small business customers the opportunity for smart thermostats, direct load control programs and time-of-use rates.

The Working Group also gathered significant information that could lead to development of a Commission policy statement containing reasonable targets for the amount of load or number and type of customers who should have access to these tools, which programs are beneficial, possible funding sources or financial incentives, and the role of consumer education. This information was assembled in four subgroup reports, Technology Deployment, Cost Recovery, Benefits and Consumer Surveys. These subgroup reports are available on the Commission’s Web site.

Also, the Commission issued standards that will allow DSR resources to participate in the alternative energy market (Order entered Oct. 3, 2005 at Docket No. 666193).
M-00061984). Act 213 of 2004 includes DSR programs in the definition of “alternative energy sources.”

Consumer Education

As stated above, on May 17, 2007, the Commission entered a Final Order outlining the need for a statewide consumer-education campaign to prepare electricity ratepayers for potential increases, as well as provide information about energy efficiency, conservation and demand side response. The PUC convened interested stakeholders -- including representatives of electric distribution companies, academic institutions, private business, professional associations, non-profit agencies, and Pennsylvania state government and government affiliates -- to develop this campaign. Communications hosted stakeholders meetings in June, August and October 2007, and January 2008. Commission staff and stakeholders were directed to research the best practices of other states that have similar campaigns.

Based on the recommendations of the stakeholder group, the Commission submitted a $5 million request to the Governor and General Assembly, for the first year of the campaign, as part of its Fiscal Year 2008-09 budget request. The Governor has not included this $5 million in his budget request submitted to the General Assembly.

The Commission has created a special Web page to keep stakeholders apprised of ongoing activities: http://www.puc.state.pa.us/electric/electric_enbanc_price_increases.aspx.

Also pursuant to the Commission’s May 17, 2007, Final Order, each electric distribution company (EDC) under the PUC’s jurisdiction has filed a proposed consumer-education plan that is tailored to their service territory. These plans were all filed by the deadline of Dec. 31, 2007.

The Commission will review each plan and issue a Tentative Order approving, rejecting or modifying each plan. Thereafter, the EDC and interested parties will have 30 days to file comments or request an evidentiary hearing before the Office of Administrative Law Judge. If no comments or petitions are filed within the 30-day period, the Tentative Order will become final. If comments or petitions are filed, the Commission will consider the comments and issue a Final Order and/or refer the matter to the Office of Administrative Law Judge for hearings.


Each plan is available at http://www.puc.state.pa.us/electric/EDC_Plans.aspx.

To date, the Commission has issued Tentative Orders approving plans for Allegheny Power (M-2008-2032275), Citizens’ Electric Company (M-2008-2032277), PPL Electric Utilities (M-2008-2032279), Wellsboro Electric Company (M-2008-666193 28
PECO Energy Company (M-2008-2032274), the FirstEnergy Companies (M-2008-2032261, M-2008-2032262, M-20082032263), Duquesne Light (M-2008-2032278) and UGI (M-2008-2032267). Tentative Orders for Allegheny, Citizens’, PPL, and Wellsboro were entered on May 6, 2008, and their comment periods are scheduled to end on June 6, 2008. PECO’s Tentative Order was entered May 22, 2008, and its comment period is scheduled to end on June 22, 2008. Tentative Orders for the FirstEnergy Companies, Duquesne, and UGI were entered on June 6, 2008. The FirstEnergy and UGI comment periods are scheduled to end on July 6 and the Duquesne comment period is scheduled to end on July 21.

**Participation in Federal Proceedings**

The Public Utility Code authorizes the Commission’s Law Bureau to represent the Commission before federal agencies, such as the Federal Energy Regulatory Commission (FERC) and federal courts. See 66 Pa.C.S.§308(b). The Commission has a long history of participation in various types of FERC proceedings in order to represent the interests of Pennsylvania and its citizens in regard to the matters regulated by FERC. The Commission has filed complaints with FERC; intervened in cases and tariff filings; and filed comments to rulemakings.

The FERC is an independent agency within the United States Department of Energy, which regulates the interstate transmission of electricity, gas and oil.

With regard to electricity, FERC:

- Regulates the transmission and wholesale sales of electricity in interstate commerce;
- Licenses and inspects private, municipal, and state hydroelectric projects;
- Ensures the reliability of high voltage interstate transmission system;
- Monitors and investigates energy markets;
- Uses civil penalties and other means against energy organizations and individuals who violate FERC rules in the energy markets;
- Oversees environmental matters related to natural gas and hydroelectricity projects and major electricity policy initiatives; and
- Administers accounting and financial reporting regulations and conduct of regulated companies.

FERC does not regulate retail electricity sales, nor does it become involved with the physical construction of generation, transmission and distribution facilities, except for backstop siting of high-voltage transmission facilities within National Interest Electric Transmission Corridors. However, FERC is the federal government agency responsible for creating, maintaining and enforcing the essential conditions for a fully competitive,
non-discriminatory wholesale market for electricity. It is also responsible for creating proper conditions and incentives to ensure the timely construction of necessary generation and transmission facilities to serve the anticipated consumer demand and to place downward pressure on prices.

When the generation portion of electric rates in Pennsylvania was deregulated, the “justness and reasonableness” of retail generation rates then would be established by competitive market forces as opposed to cost of service-based rate regulation. The effectiveness of those competitive market forces in producing reasonable generation rates at the wholesale level, which are then reflected in retail generation rates, depends greatly on FERC’s policies, regulations and decision making. Accordingly, since a properly functioning and competitive wholesale market is integral to the existence of a properly functioning and competitive retail market with reasonable prices for consumers, the Commission participates in many proceedings related to the design and operation of the two regional transmission organizations (RTOs) in which Pennsylvania is located. These RTOs are the PJM Interconnection Inc. and the Midwest Independent Transmission System Operator Inc. (MISO). Most of Pennsylvania’s counties are within PJM's service territory. The Commission also participates in various FERC proceedings filed by and against utilities.

This is a summary of recent FERC proceedings in which the Commission has participated:

- PJM Reliability Pricing Model (RPM)
- PJM Cost of New Entry (CONE)
- Complaint Against PJM re: Interference with the PJM Market Monitoring Unit
- PJM Complaint against PowerEdge
- Duquesne Light Company Withdrawal from PJM
- ANOPR on Organized Markets
- Duquesne Incentive Transmission Rate Request
- Allegheny Incentive Transmission Rate Request (TrAILCo)
- AEP Incentive Transmission Rate Request (PATH)
- PJM and MISO Fixed Transmission Rights
- MISO Resource Adequacy
- Neptune Transmission Line

In addition to the above proceedings before FERC, the Commission has recently brought federal court litigation to challenge the Department of Energy’s designation of most of Pennsylvania as a National Interest Electric Transmission Corridor (NIETC) pursuant to the Energy Policy Act of 2005. The Commission has brought an action in federal court in the Middle District of Pennsylvania and also is appealing the DOE NIETC designation in the federal circuit courts of appeal. In general, the Commission’s lawsuits allege that the DOE’s designations for Pennsylvania are overly broad, unlawfully usurping traditional state control over transmission line siting, and in violation of the Energy Policy Act of 2005 standards for making such determinations.
Finally, the Commission is a member of two organizations made up of state commissions -- the Organization of PJM States Inc. (OPSI) and the Organization of MISO States Inc. (OMS). The Commission participates with these organizations before FERC and also on its own behalf.

**D. Recommendations for Legislative Consideration**

The resolution requests the Commission "to make written suggestions on how certain laws may be changed to reduce the incidence of rate shock and the impact of rate shock". The resolution refers to the price increase in Pike County after the rate cap for Pike County Light & Power expired and the increases in Delaware and Maryland. The increases in Delaware and Maryland show that the higher costs for generation are not limited to Pennsylvania, but reflect increased cost on both regional and national levels.

It is important to note that the rate caps authorized by law and, in some cases, extended by settlements, did not cause the increases. There is no question that the costs of construction and fuel for electric generation facilities have increased substantially since 1997 and that such increases would have been reflected in generation costs in the absence of rate caps. However, the rate caps have largely insulated customers from the ongoing increases in electric generation costs.

Because consumers' current generation rates are below the market price for generation due to the rate caps, there will be some degree of rate increases when rates begin to reflect the current market prices for generation. These differences will be less pronounced in service territories which had above-market pricing prior to the Customer Choice Act and greater where the prices were lower.

In the Commission's opinion there are several options which the General Assembly could consider when evaluating what changes to make in the law. However, before addressing those options, the Commission believes the General Assembly must recognize that there are state and federal policy goals which also contribute to increased prices to consumers.

For example, the federal Energy Policy Act of 2005 recognized the need for greater investment in the high-voltage transmission infrastructure to improve reliability, reduce congestion costs and facilitate wholesale competition. The process for siting new transmission lines in and around Pennsylvania has already begun. This infrastructure is expensive. The line in Southwestern Pennsylvania proposed by Allegheny Energy is estimated to cost approximately $1 billion.

Similarly, renewable portfolio standards, such as the Alternative Energy Portfolio Standards Act, require utilities to purchase increasing percentages of renewable generation, to reduce our dependence on fossil fuels and provide support to nascent alternative technologies for the production of energy. This new generation often has a
higher cost per kilowatt hour, at least in the short term, than traditional sources of generation. However, such generation provides environmental benefits, energy self-sufficiency, job creation and other laudable public policy goals.

The first area for potential changes in the law is for the General Assembly to establish tools the Commission can use to increase its efforts to promote energy conservation. This includes demand response, energy efficiency and "smart" meters. To a large degree, existing Special Session Bills, HB 2200 and HB 2201, go a long way to creating these tools. These bills provide for reasonable energy efficiency and demand response goals for electric distribution companies, as well as procedures for Commission review and extension of those goals if warranted based on cost/benefit analyses. In addition, the introduction of smart meters, together with voluntary “time-of-use” rates, will provide consumers with a valuable tool that both individually and on a system-wide basis can reduce the costs of generation.

The second area is to provide the Commission and customers with increased options to aggregate load. Aggregation is when a group of customers join together to form a single, larger customer that buys energy for its members. A large buying group may be able to get a better price for the group members than they could get individually. The Commission has some authority in this regard which we exercised in the Pike County service territory to permit Direct Energy to provide service on an aggregated basis.

The Customer Choice Act promotes aggregation. However, it does this on a retail level by permitting brokers and marketers to aggregate load. Several states, the most successful being Ohio, have deregulation laws permitting municipal aggregation by villages, towns and counties for their citizens.\footnote{http://www.puco.ohio.gov/PUCO/Consumer/Information.cfm?id=4068} This reduces customer acquisition costs to the competitive supplier. One drawback to municipal aggregation is the political risk which could occur if market prices fall below the rates negotiated by the municipality.

Approximately 30 boroughs in Pennsylvania have municipal electric systems. These systems differ from municipal aggregation because these borough systems handle the distribution function as well as the acquisition of generation supply on a wholesale basis. With municipal aggregation, there is an electric generation supplier selected which provides the generation services to all the residents who have either opted into the aggregation pool, or not opted out (in "opt-out" situations).

One additional option, which does not require new laws, is the development of rate stabilization programs. Rate stabilization programs have been used in some states to transition from capped rates to market based rates. These programs can be voluntary, such as the Rate Stabilization Plan filed by PPL Electric Utilities Inc., presently being considered by the Commission. Alternatively, such programs can mandatory as in Ohio.
There are problems with mandatory rate stabilization programs. The Ohio law led to litigation by all three utilities subject to it. Moreover, in a rising generation cost environment, rate stabilization programs may simply defer significant price increases as did capped rates.

**E. Conclusion**

When the Customer Choice Act was passed in 1996, the Commission was tasked with overseeing the transition to a fully competitive market. With the expiration of generation rate caps on the horizon for the majority of Pennsylvania’s electric consumers, the Commission appreciates the legislature’s attention on these challenging issues. Importantly, the Commission is also grateful for the legislature’s inclusion of our agency in the many discussions and hearings associated with the special session on energy policy. We will continue to manage the transition as effectively as possible within the existing framework, and we stand ready to implement any statutory amendments that the General Assembly and the Governor enact to address these challenges.
Appendix 1 – Final Rulemaking Order
The Electricity Generation Customer Choice and Competition Act (the “Competition Act”), 66 Pa.C.S. §§ 2801-2812, requires the Commission to promulgate regulations defining the obligation of electric distribution companies (“EDC”) to serve retail electric customers at the conclusion of the restructuring transition periods. On December 16, 2004, the Commission issued proposed regulations for public comment on this subject. On February 8, 2007, the Commission issued an advance notice of final rulemaking (“ANOFR”) for public comment. The Commission has completed its review of the comments to the ANOFR, and today issues a final form default service regulation. At separate dockets, we are issuing a final policy statement on default service and retail
electric markets, and identifying other policies for addressing potential electric price increases.18

**BACKGROUND**

Section 2807(e)(2) of the Competition Act requires the Commission to promulgate regulations governing an EDC’s obligation to serve retail customers after the conclusion of its transition period. 66 Pa.C.S. § 2807(e)(2). This duty is often referred to as the “provider of last resort” (“POLR”) obligation. As the Competition Act makes clear, the purpose of this obligation is to address the scope of retail electric service that must be provided to customers who either have not chosen an alternative electric generation supplier or who contracted for electric energy that was not delivered. Section 2807(e) of the Competition Act provides several directives that the Commission must follow in its promulgation of regulations on this subject:

(2) At the end of the transition period, the commission shall promulgate regulations to define the electric distribution company’s obligation to connect and deliver and acquire electricity under paragraph (3) that will exist at the end of the phase-in period.

(3) If a customer contracts for electric energy and it is not delivered or if a customer does not choose an alternative electric generation supplier, the electric distribution company or commission-approved alternative supplier shall acquire electric energy at prevailing market prices to serve that customer and shall recover fully all reasonable costs.

(4) If a customer that chooses an alternative supplier and subsequently desires to return to the local distribution company for generation service, the local distribution company shall treat that customer exactly as it would any new applicant for energy service.

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The proposed regulations were published in the Pennsylvania Bulletin, Volume 35, No. 9, on February 26, 2005. A 60 day comment period and 60 day reply comment period followed, the latter of which concluded on June 27, 2005. The Independent Regulatory Review Commission (the “IRRC”) filed comments to this proposed rulemaking order on July 27, 2005.

The Commission reopened the public comment period in late 2005 to address the relationship between the default service rulemaking and the Alternative Energy Portfolio Standards Act of 2004. 73 P.S. § 1648.1, et seq. (“AEPS Act”). This second public comment period concluded on April 7, 2006. The IRRC stated in a letter dated May 8, 2006, that it had no additional comments, and that the due date for a final default service rulemaking had been extended to April 7, 2008.

On February 8, 2007, the Commission issued an ANFOR at this docket. The ANOFR included numerous changes to the proposed rule intended to address concerns raised by the IRRC and other parties, and to reflect changes in Commission policy on a number of issues. Comments and reply comments were requested. Separately, the Commission issued a proposed policy statement on certain issued relating to default service and retail choice. Default Service and Retail Electric Markets, Docket No. M-00072009 (Proposed Policy Statement Order entered February 9, 2007).

Comments to the proposed rulemaking order and/or ANOFR were filed at this docket by many parties, including the Allegheny Conference on Community Development, Allegheny Power (“Allegheny”), BP Solar, Citizens for Pennsylvania’s...

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21 The Industrial Energy Consumers of Pennsylvania, the Met-Ed Industrial Users Group, the Penelec Industrial Customer Alliance, the Philadelphia Area Industrial Energy Users Group, and the PP&L Industrial Customer Alliance.
SUMMARY OF CHANGES

The Commission has made significant changes to the proposed regulations issued on December 16, 2004. We have determined that the public interest can best be served by modeling certain portions of the default service rules on our form of regulation of natural gas supply costs. That is, there should be regular adjustments to default service rates to reflect changes in the actual, incurred costs of the default service provider (“DSP”). This practice of regular adjustment with the use of spot market energy supply products will ensure that rates more closely track prevailing wholesale energy prices, and that customers do not experience large changes in rates as program terms expire. When wholesale energy prices rise over a period of several years, we find that a series of small rate increases is to be preferred to one large increase at the end of a plan’s term of service. Reconciliation is strongly encouraged, though not mandated, in order to ensure the full recovery of the DSP’s reasonable costs.

DSPs should consider a portfolio of energy supply products when developing their procurement plans. A reasonable procurement strategy may include a mix of fixed-term and spot market energy purchases, the use of laddered contracts, etc. The Commission discourages the practice of procuring all needed supply for a period of service at a single point in time. Instead, we recommend that the DSP use multiple competitive procurements and spot market purchases to meet its obligations and to reduce the risk of acquiring all supply at a time of unusual price volatility. We expect that DSPs will gradually increase their reliance on shorter term contracts and spot market energy products over time.

Rate design should be simplified to provide normal incentives for energy conservation and to facilitate customer choice. This will be done through the elimination of declining blocks rates and some demand charges. These designs may be gradually phased out to mitigate the bill impact for customers. Each default service customer will
be offered a single rate option, which will be displayed on a customer’s monthly bill as the Price-to-Compare (“PTC”). The PTC is an informational tool designed to facilitate customer choice, and represents the sum of all unbundled generation and transmission charges associated with default service. Additionally, customers may have the option of selecting an alternative time based rate if the Commission separately determines that the public interest requires DSPs to offer such rates to customers.

The Commission is mindful of the risks of being too prescriptive in its approach to this rulemaking. Changes in markets, technology and applicable law may result in an approach that is too narrowly tailored to serve Pennsylvania’s interests. Accordingly, we do not attempt to dictate the exact manner by which every DSP will acquire electricity, adjust rates, and recover their costs. The Commission is issuing a separate policy statement that contains guidelines for DSPs in the areas of procurement, rate design, and cost-recovery. Reserving some aspects of our regulation of default service to a policy statement will allow the Commission, DSPs, retail customers, and other market participants to consider these policies in the context of individual default service plans, and to more effectively respond to changes in retail and wholesale markets.

DISCUSSION

The Commission has reviewed the comments filed at each stage of this proceeding. For purposes of this Final Rulemaking Order, we will focus on revisions to the proposed regulations and ANOFR, and the issues raised by the IRRC in their comments of June 27, 2005.

In developing this final form rule, the Commission has attempted to craft rules that reflect stakeholder consensus to the extent that any agreement is aligned with the requirements of the Competition Act and the interest of ratepayers. We have found, as
evidenced by the comments, that there is relatively little consensus on most of the key issues addressed by this rulemaking proceeding, including energy procurement, rate design and cost-recovery. This is not surprising, given the divergence in interests among those participating in this rulemaking process.

We make this observation cognizant of the fact that this rule is subject to the review of the Pennsylvania General Assembly (“General Assembly”) and the IRRC, and that interested parties are free to support or oppose this regulation in those forums. We find that this rule achieves the objectives of the Competition Act on issues relating to default service, including the acquisition of electricity at prevailing market prices, customer choice of generation suppliers through direct access, and the full recovery of reasonable costs for EDCs. There is sometimes a tension between these and the other objectives of the Competition Act that, if not balanced appropriately, can frustrate the intent of the General Assembly. The Commission has therefore crafted a regulatory framework that does not unreasonably advance one objective to the extent that it obstructs others. Consequently, to the extent that changes to this final form rule are required as part of the regulatory review process, such revisions may not occur in isolation.

A. Need for Regulations, Currently Effective Default Service Plans, and Pending Default Service Proceedings.

In its first comment, the IRRC questioned whether the Commission was promulgating regulations too far in advance of the expiration of rate caps. Several parties who participated in the POLR Roundtable proceeding in 2004 recommended that the Commission wait at least several more years before promulgating regulations. These parties cautioned that changes in retail and wholesale markets might render ineffective any regulations adopted too far in advance of the end of the transition period. The IRRC noted that additional experience, including more study of default service models in other
states, and further consideration of the requirements of the AEPS Act, might benefit the Commission in preparing regulations.

We believe this issue has been resolved given the passage of time since we proposed this rule. Six EDC generation rate caps have expired, and the remaining ones will end by December 31, 2010. The Commission has also had the benefit of several more years to study how neighboring jurisdictions are managing POLR service and the expiration of rate caps. The Commission now has a significantly better understanding of the impact of the AEPS Act on default service than it did in 2004. We have also learned from the experience of several Pennsylvania EDCs who have concluded their transition periods and implemented default service plans since 2004. Finally, the overwhelming majority of stakeholders would prefer to have regulations finalized as soon as possible. Accordingly, the Commission finds that it would be appropriate to conclude the default service rulemaking by mid-2007. This will provide needed regulatory certainty to those EDCs preparing their first default service programs, who collectively serve the large majority of Pennsylvania ratepayers.

The Commission has already approved interim default service plans for six EDCs that have completed their transition periods.22 A number of parties, such as Duquesne, UGI, the Energy Association, and the OSBA, have asked that the Commission clarify the impact of final regulations on plans that are effective or now under Commission consideration.23 It has been suggested that this issue be addressed by delaying the effective date of these regulations until January 1, 2011, when the last EDC generation rate cap has expired.

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23 Default service proceedings are currently pending before the Commission for Duquesne, PCLP and the Pennsylvania Power Company. Citizens and Wellsboro are also expected to file plans for our consideration during 2007.
The Commission will not apply these regulations to already effective default service plans. In Pennsylvania, the retroactive application of laws is disfavored when it affects the substantive rights of parties. *Giant Eagle, Inc. v. Worker’s Compensation Appeal Board*, 764 A.2d 663 (Pa. Cmwlth. 2000). Most of these interim default service plans will expire within the next twelve months, and we can find no public interest in disturbing their terms and conditions of service for so short a period of time.

Nor will the Commission require EDCs with pending default service proceedings to withdraw their filings and submit new plans. The Commission will not know if these final form regulations have obtained all necessary regulatory approvals for several months. Even assuming these regulations are approved by the end of July 2007, we question whether there would be sufficient time for EDCs to seek Commission approval of new, amended default service plans and obtain supply at reasonable prices prior to the expiration of their currently effective rates on December 31, 2007.24

However, the Commission will not grant a blanket waiver of these regulations at this time for plans now, or soon to be under, consideration by the Commission. Instead, the Commission recommends that EDCs with pending plans evaluate whether they wish to amend their filings. EDCs should take into consideration whether the delay of these proceedings resulting from an amendment would materially prejudice their ability to procure energy prior to the expiration of currently effective rates. If EDCs do not wish to amend their pending plans, they should request a waiver, in the pending proceeding, from any provision of the approved regulations that conflicts with their proposal. In reviewing any waiver requests, the Commission will be guided by its stated policy objectives of mitigating the impact of potential electric price increases for retail customers.

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24 Currently effective rates for Duquesne, PCLP, Citizens and Wellsboro will expire on December 31, 2007.
B. § 54.123. Competitive safeguards

The IRRC commented that certain proposed safeguards may improperly restrain customer choice, which is protected by Section 2807(e)(4) of the Competition Act. We have deleted the language the IRRC identified as problematic. The Commission will instead rely on its powers to prosecute and assess civil penalties on electric generation suppliers for violations of the Code of Conduct at 52 Pa. Code § 54.122 and other relevant regulations and statutory provisions. Given our finding that rates be regularly adjusted to reflect changes in the composition of the DSP’s portfolio, we find that the risk of an EGS exploiting seasonal price variation, to the detriment of the DSP, is greatly reduced.

C. § 54.181. Purpose

The IRRC commented that this section should be revised to reflect that parties other than EDCs may be approved to serve as a DSP. Any DSP, whether they are an EDC or not, is entitled to full recovery of reasonable costs. Accordingly, the phrase “other approved entity” has been added to the last sentence of Section 54.181. The purpose of our default service regulatory framework is expanded upon in the final policy statement on “Default Service and Retail Electric Markets.”

D. § 54.182. Definitions

The Commission received many comments on the proposed definitions and this section reflects some revisions. Certain terms have been deleted given changes in other parts of the regulation, and new terms have been added. The IRRC provided comments
on four different definitions. “Default service provider” has been modified consistent with the IRRC’s suggestion to comply with the Pennsylvania Code & Bulletin Style Manual. “Fixed rate option” and “hourly priced service” have been deleted from this section given our changes to the section on rate design and cost recovery. The definition for “competitive procurement process” has been revised, and we will respond to the IRRC’s comment on this issue in subsequent sections of this final order.

New definitions have been added, including PTC, maximum registered peak load, and spot market energy purchase. These definitions are required due to other changes to the regulations that will be discussed in subsequent sections of this final order.

Definitions have been further revised based on comments to the ANOFR by PPL and the Energy Association. For example, the word “lowest” has been added to the definition for “competitive bid solicitation process” to be consistent with the version that appears in the default service policy statement. The definition for “default service” has also been clarified. Additionally, the definition for PTC has been revised to reflect that it is intended to serve as a new line item to facilitate customer choice.

E. § 54.183. Default service provider

The IRRC asked the Commission to explain its decision in Section 54.183(a) to require the EDC to serve as the DSP unless the Commission approves an alternative. The IRRC observes that Section 2807(e)(1) of the Competition Act requires an EDC to assume this role while it is recovering stranded costs, but that it does not mandate that this role continue indefinitely. This description of the statutory language is correct.

However, the Commission cannot assume that there will be other parties qualified to or even interested in taking on the DSP role. There must be a DSP already in place in
each territory to serve retail customers the day generation rate caps expire. Accordingly, the Commission must pick some party to be the initial DSP. The EDCs are the only parties that currently have certificates of public convenience to provide electric utility service in all of their particular territory. As the holder of a certificate, the EDC cannot refuse to serve retail electric customers within its designated service territory. The Commission cannot force another party, such as an EGS, to assume the DSP role. Therefore, the Commission has no choice but to initially designate the EDC to assume the DSP role. Section 2802(16) of the Competition Act clearly gives the Commission this authority:

Electric distribution companies should continue to be the provider of last resort in order to ensure the availability of universal electric service in this Commonwealth unless another provider of last resort is approved by the Commission.

66 Pa.C.S. § 2802(16). This section does not include language supporting a limitation of the DSP role to the transition period. Additionally, the Commission does not interpret Section 2807(e)(2) as in any way requiring the Commission to allow an EDC to exit this function. The Commission has been granted broad authority by the General Assembly to define the obligations of EDCs after the transition has expired, including whether they are to continue in the role of the DSP. Designating the EDC as the initial DSP in each service territory is a reasonable approach to take in order to ensure the availability of electric service to all customers. Section 54.183 of these regulations identifies a process by which the DSP can be changed from an EDC to another party, as allowed by Section 2807(e)(2), when the Commission finds it to be in the public interest. The Commission’s interpretation of the Competition Act is reasonable and consistent with the intent of the General Assembly.

In regards to Section 54.183(b), the IRRC has requested that the Commission provide more specific criteria for changing the DSP. The Commission agrees that more
specific criteria are appropriate. This version includes proposed changes to address this issue. The Commission draws on Sections 1103, 1301, and 1501 and 2807(e)(3) of the Public Utility Code, 66 Pa.C.S. §§ 1103, 1501, 2807(e)(3), in developing these criteria. Section 1103(a) requires that the Commission only award a certificate of public convenience when finding that utility service is necessary for the “… accommodation, convenience, or safety of the public.” Section 1301 requires that all rates charged by a utility be “just and reasonable.” Section 1501 requires that the conditions of public utility service “. . . be adequate, efficient, safe, and reasonable.” Section 2807(e) finds that a DSP can only recover “reasonable” costs. Thus, if an EDC can no longer provide default service in a safe and efficient manner, and/or in a way that reflects the incurrence of reasonable costs, the Commission may make a finding that other parties should be considered for the role.

The IRRC identified several concerns regarding Section 54.183(c). It asked whether it would be appropriate to require an EGS or EDC to obtain a certificate of public convenience if it wished to assume the DSP role. We now conclude that a certificate is not necessary, and have eliminated that requirement. We have also identified criteria, similar to those in 54.183(c), for selecting from among more than one qualified parties who wish to serve as the alternative DSP. Finally, we observe that to the extent that an alternative DSP is approved, this entity will be subject to assessments for the Commission’s regulatory expenses. Specifically, we would require a party to agree to subject themselves to regulatory assessments as a condition of becoming an alternative DSP.

If a party does not wish to be responsible for these costs, then they should not seek to become a DSP. The Competition Act does not give any party a statutory right to become an alternative DSP. The Commission, at its discretion, may impose terms and conditions it believes to be appropriate for the reassignment.
In response to comments by Strategic to the ANOFR, we have made other revisions to Section 54.183(c) in order to be able to fully utilize the potential of alternative DSPs. For example, it may be in the public interest to reassign some, but not all, customer classes to an alternative DSP. It may also be appropriate to utilize more than one alternative DSP if the obligation is assigned. One alternative DSP could be approved for residential and small business customers and a separate DSP for large customers.

F. § 54.184. Default service provider obligations

The IRRC asked that the Commission more specifically identify what regulations and statutory provisions a DSP must adhere to. We have added these references for purposes of clarity at Section 54.184(b).

The IRRC properly raised the issue of whether an alternative DSP would have a universal service obligation. In the event that a reassignment occurs, the incumbent EDC’s universal service obligation must be addressed. The Commission finds that the Competition Act requires that consumer protections be maintained at the level they existed at the time of the Competition Act’s passage. 66 Pa.C.S. § 2802(10). In Section 54.184(c), the Commission now acknowledges that if an EDC is relieved of the default service obligation, consideration will need to be given to the proper allocation of universal service responsibilities between that EDC and the replacement DSP. Universal service programs must be maintained at the same level in the event of the reassignment of the DSP role.

In a recent order the Commission provided guidance on the recovery of universal service program costs. *Customer Assistance Programs: Funding Levels and Cost Recovery Mechanisms*, Docket No. M-00051923 (Final Investigatory Order entered
The order provides that utilities may propose a surcharge to recover the costs of these programs from residential customers.

Even if the DSP role is reassigned, the incumbent EDC will still be providing transmission and distribution service to retail customers. Universal service programs cover the costs of transmission, distribution and generation service. The proper solution may be for the EDC to continue to administer and recover all costs for universal service programs. The EDC could then reimburse the alternative DSP for whatever services are provided by the DSP.

Some parties commented on this issue in their response to the ANOFR. For example, PPL recommended that the universal service obligation be largely shifted to the alternative DSP. However, the OCA and FirstEnergy believes that this function should remain with the incumbent EDC. In the absence of any actual experience with reassigning the full default service role, we are reluctant to issue a blanket rule at this time. A uniform standard may be developed after the Commission has adjudicated a petition to reassign the DSP role.

At the suggestion of the OCA, we have also made express the DSP’s obligation to serve retail customers whose EGS has defaulted on their obligation to provide generation service. This revision is made at Section 54.184(a).

G. § 54.185. Default service programs and terms of service

This section has been significantly revised. Pursuant to 54.185(a), DSPs will be filing “default service programs” instead of implementation plans, and this definition has been added to Section 54.182. Responding to the IRRC’s question on alternative DSP filings, the Commission notes that no alternative DSPs have been approved, and no
requests are pending. In the event that an alternative DSP was approved after this regulation became effective, we would expect that the alternative DSP file its program at least twelve months prior to the expiration of the generation rate cap or approved default service program in that service territory. If this is not possible due to the timing of the reassignment, a waiver of this provision could be sought, consistent with 52 Pa. Code § 5.43.

Section 54.185(b) has been amended consistent with the IRRC’s recommendation to identify the documentary filing regulations that must be adhered to. Therefore we are including a reference to 52 Pa. Code § 1.1, et seq. We are also directing the DSP to serve a copy of its default service program on any EGSs registered in the DSP’s service territory, and to make it available on their public internet domain.

After reflecting on the IRRC’s and other parties comments on this issue, the Commission has revised the language of Section 54.185(c) on program duration by selecting a two to three year term for the first default service program filed after the effective date of these regulations. The Commission has not been able to identify an optimal program duration based on its current knowledge of energy markets. This issue has therefore been reserved to the default service policy statement, which recommends a standard duration of two years for subsequent programs. As wholesale and retail markets change over time, the Commission will provide guidance on appropriate program durations. If markets mature to the point where the Commission can identify the ideal program duration, this regulation will then be revised accordingly.

We also agree with the IRRC’s comment to this section about excessive reliance on energy contracts of greater than one year. We are encouraging DSPs to gradually increase their utilization of spot market purchases and short fixed term contracts, a subject which is discussed at length in this order. The final policy statement we are issuing contains guidelines on this topic.
Section 54.185(d) of the proposed rules has been eliminated, as procurement specific requirements have been moved to the new section 54.186. The revised 54.185(d) identifies the required elements of the default service program. The default service program will consist of three main elements: a procurement plan for acquiring electric generation supply, an implementation plan that identifies the schedules and technical requirements of these procurements, and a rate design plan. The program will also include documentation of compliance with the RTO requirements, a contingency plan in the event of supplier default, copies of all agreements and forms to be used in competitive solicitations, and schedules identifying generation contracts with existing customers.

Section 54.185(e) remains largely the same in the final form version. The Commission recognizes that retail customers may benefit from the economies of scale realized by combining the procurements of more than one service territory into a single auction process. DSPs may submit such proposals for our consideration.

The Commission is also concerned about the possibility of DSPs scheduling multiple, large procurements at the same point in time. This might negatively impact the price of bids. Guidelines on this issue are included in the default service policy statement. We will work with relevant parties to balance the potential benefits associated with building economies of scale, with the associated increase in interest by suppliers, versus potential complications related to suppliers having to commit a large amount of their generation portfolio at a single point in time.

Section 54.185(f) has been moved to 54.185(d)(4) and is largely unchanged. The term ISO, which stands for Independent System Operator, has been dropped from this section as no Pennsylvania EDC is under the operational control of an ISO. While PCLP is owned by a member of the New York Independent System Operator (“NYISO”), its transmission system is not under the NYISO’s operational control.
Section 54.185(g) has been moved to 54.185(d)(3). Sections 54.185(h) and (i) have been deleted. Section 54.185(j), now 54.185(d)(7) has been revised from “long term generation contracts” to “generation contracts greater than two years” to respond to a comment from the IRRC. Section 54.185(k), has been moved to 54.185(d)(6) and expanded to include all forms and agreements used as part of the default service implementation plan. The inclusion of these documents has been made mandatory, consistent with the recommendation from the IRRC. Section 54.185(l) has been moved to 54.185(d)(5), and left largely unchanged. Section 54.184(m), which the IRRC identified some concerns with, has been deleted.

In response to comments to the ANOFR by FirstEnergy and others, the time for the filing of a default service program has been reduced from fifteen to a minimum of twelve months in advance of the expiration of the current program at Section 54.185(a). However, DSPs should give consideration to filing more than twelve months ahead of time, particularly for complex or initial post-rate cap default service programs.

We also received responses to our request for comments in the ANOFR on the coordination of procurements. PPL, PECO, FirstEnergy, Allegheny and Constellation have all expressed an interest in some form of coordinated, statewide or multi-territory procurement process with uniform rules. We agree that such an approach may reduce administrative costs and facilitate wholesale supplier participation. Additionally, as recommended by Constellation, the Commission has no objection to the use of a single independent consultant to manage a multi-territory, coordinated, procurement process. However, a multi-service territory default service program must comply with the other aspects of this rule, including procurements by customer class, regular adjustments of rates, etc.

25 The Commission has initiated a separate proceeding to develop standardized request for proposal forms and supplier master agreements at Docket M-00061960.
Both Citizens and Wellsboro filed comments to the ANOFR and default service policy statement highlighting the challenges faced by smaller EDCs in managing the default service obligation. For example, these EDCs comment that they may have difficulty managing a portfolio of resources, multiple procurements, etc., even if they were to aggregate their load. They suggest that the Commission make more express its willingness to grant small DSPs waivers from appropriate provisions.

We agree that smaller DSPs such as Citizens, Wellsboro, PCLP and, to a lesser extent UGI, face different challenges than larger EDCs, and have fewer resources to manage their obligation. Accordingly, we are adding Subsection 54.185(f) to the final form rule. This has two purposes. First, it puts all DSPs on notice that they should include all requests for waivers to this subchapter in their default service program filings. Second, it affirms that special consideration will be given to the waiver requests of DSPs that serve smaller numbers of customers.

Section 54.185(d)(7) has been revised in response to a comment to the ANOFR by IECPA. Schedules identifying each generation contract between the incumbent EDC and customers shall only be provided to the Commission. Individual customer information will be given confidential status.

H. § 54.186. Default service procurement and implementation plans

This section has been substantially revised. We will first address the IRRC’s comments to both this section and 54.185(d) regarding the requirement for competitive procurement processes. The IRRC and some other commentators question the need to prescribe the manner in which electricity can be procured. The IRRC observes that Section 2807(e) does not expressly mandate that competitive bidding be used to procure
electric generation supply for default service customers. The IRRC recommends that this be modified, and that the Commission should be disinterested as to the method for procurement, so long as supply as acquired at prevailing market prices.

Initially, we must observe that we are expressly charged by the General Assembly with defining the obligation to “acquire” electricity:

At the end of a transition period, the commission shall promulgate regulations to define the electric distribution company’s obligation to connect and deliver and acquire electricity under paragraph (3) that will exist at the end of the phase-in period.

66 Pa.C.S. § 2807(e)(2) (emphasis added). The scope of this rulemaking properly includes the acquisition of electricity. This obligation cannot be defined without addressing the method of the acquisition.

It is true that electric utilities do routinely acquire electricity through bilateral contracts that are not a result of competitive procurement processes. These bilateral contracts may very well reflect “prevailing market prices.” However, the Commission concludes that the optimal method of acquiring electricity includes a direct exposure to market forces. This exposure can best occur either through a competitive procurement process or a purchase in a spot energy market managed by an RTO such as the PJM Interconnection, LLC. We note it is the standard practice of the Commonwealth of Pennsylvania to use competitive bidding when procuring goods or services of significant value. 62 Pa.C.S. § 101, et seq.

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26 We remind the IRRC that most Pennsylvania EDCs have wholesale energy supplier affiliates with substantial generation assets. Permitting the routine use of bilateral contracts would allow an EDC to negotiate a contract with its affiliate, with all the potential risks and conflicts of interest this would entail. Requiring competitive procurements largely eliminates the risk that an EDC’s wholesale energy affiliate would be given some preference in the procurement of default service supply. Some parties who commented to the ANOFR suggested that the Commission allow bilateral contracts with non-affiliates. As discussed in this section, the Commission is very skeptical of a DSP’s ability to obtain the best price for customers with bilateral, long-term contracts.
In considering this rulemaking, the IRRC should be cognizant of one of the key findings of the General Assembly included in the “Declaration of policy” section of the Competition Act:

**Competitive** market forces are more effective than economic regulation in controlling the cost of generating electricity.

66 Pa.C.S. § 2802(5) (emphasis added). In interpreting a statute, legislative intent controls. 1 Pa.C.S. § 1921. We find that the plain language of the Competition Act demonstrates a preference for the use of “competitive market forces” in controlling the cost of electricity. The regular use and Commission approval of no-bid, bilateral energy contracts would be an exercise in “economic regulation” of the sort that the Competition Act discourages. We conclude that Section 2807(e) must be read together with the General Assembly’s declarations of policy at Section 2802. The optimal forms of default service procurement are therefore competitive bid solicitations and spot market energy purchases. The recognition that spot market purchases are appropriate is a change from the proposed version of the rules, and consistent with the IRRC’s request that DSPs be given more procurement options and that the Commission allow procurements that reflect “prevailing market prices.” The Commission’s interpretation of the Competition Act is reasonable and reflects the intent of the General Assembly.

However, the Commission recognizes that there may be some circumstances where a short-term, bilateral contract is necessary and appropriate. For example, in the event that a wholesale energy supplier would default on a contract, the DSP would need to acquire replacement supply. We would not want to limit the DSP to acquiring electricity in only the spot market. In that situation, one or more bilateral contracts of 1-3 months may be appropriate until a permanent solution could be achieved, and may be incorporated in a DSP’s contingency plan. To the extent a DSP believes an exception to the procurement standard is required regarding bilateral contracts, a petition for waiver may be filed pursuant to 52 Pa. Code § 5.43.
Section 54.186 has been significantly revised as to form and content. Section 54.186(a) provides that supply will be acquired consistent with Commission approved default service procurement and implementation plans. Section 54.186(b) identifies procurement plan standards, some of which are new to this version. This includes the requirement to use competitive procurement processes or spot market energy purchases only. This change is at least partly in response to the IRRC’s comment to the proposed 54.187(b), that rates includes seasonal or monthly variation to reflect the prevailing market prices. Incorporating spot market products in a DSP’s portfolio, when coupled with the regular adjustment of rates, will ensure that retail rates are responsive to changes in wholesale market prices.

Procurement plans should have the objective of obtaining the lowest, reasonable price. Given our recent experience with PCLP, we recognize that small DSPs have a greater challenge in attracting the interest of wholesale energy suppliers. Accordingly, they are directed to consider the benefits of coordinating their procurements with other DSPs. Section 54.156(b)(1), relating to affiliate participation, has been moved to Section 54.156(b)(5).

Section 54.156(b)(2) has been moved to 54.156(c)(1) in this version with few changes. In responding to the IRRC’s questions regarding bid evaluation criteria, we are revising this to “price-determinative bid evaluation criteria.” It is our expectation that the energy suppliers who submit the lowest priced bids, providing they have met all bidder qualification criteria, will be awarded generation contracts by the DSP. Issues regarding the reliability and creditworthiness of a supplier should be addressed in bidder qualification criteria.

The original 54.156(c) has been deleted and 54.186(d) has been moved to new 54.186(c)(3). Consistent with the IRRC’s and other parties’ recommendations, third
party oversight is now a mandatory part of this process. Guidelines for selecting a third party evaluator are addressed in more detail in the default service policy statement.

The original 54.186(f) has been deleted and its substance is addressed in the revised 54.188. In the revised 54.188, we address the IRRC’s comment on the old 54.186(f)(2) that we reduce the time to review competitive procurement results.

We have also responded to the IRRC’s comment on contingency plans at 54.186(g) (and 54.187(i) and 54.188(e)). The prior versions of these sections have been deleted as duplicative or otherwise revised or moved to new sections. Contingency plans must be still included in the default service program, at the new 54.185(d)(5). The terms and conditions of a contingency plan will be subject to Commission review as part of the examination of the default service program under the procedures at the revised 54.188. Responding to the IRRC’s comment on “acquisition strategies”, we find that acceptable contingency plans may incorporate spot market purchases, a competitive bid solicitation process (if time permits), or a short-term bilateral contract, as acknowledged previously in this section. Individual spot market purchases do not require prior Commission approval, consistent with the revised 54.188. When issuing an order on a particular default service program, the Commission would clearly address the level of Commission oversight in the execution of a contingency plan.

Section 54.186(h) has been moved to 54.186(c)(5). Additional guidelines regarding confidentiality of information are addressed in the default service policy statement.

In response to a comment by UGI to the ANOFR, the words “to the extent applicable” have been added to 54.186(c)(1) to acknowledge the fact that a DSP may not solely procure load following service. For example, a DSP has the discretion to use other types of contracts including on-peak, off-peak, or structured block products (e.g., 7 days a
week, 24 hours a day), etc., as part of its procurement plan. In response to a comment by PPL, Section 54.186(c)(1)(vii) has been revised to state that data may need to be provided according to the divisions in maximum registered peak load, as opposed to customer class. We have also adjusted the wording of this subsection, in response to a comment by FirstEnergy to the ANOFR, to ensure that “current” load information be made available to suppliers at an “appropriate time,” which will likely be a time closer to the actual competitive bid process. The reference to 54.186(b)(2)(vi) in Section 54.186(c)(4) of the ANOFR, which was intended to refer to price determinative bid criteria, has been corrected to 54.186(c)(1)(vi).

In response to comments by Strategic and other parties, we wish to clarify that Section 54.186(b)(3), which allows for supply contracts that extend beyond the duration of the program term, is primarily intended to address the subject of contract laddering. The Commission recognizes that the laddering of supply products may be a valid element of a portfolio strategy, particularly in the initial period following the expiration of rate caps. For laddering to occur, it may be necessary for some portion of the supply acquisition to overlap the end of one program term, and the beginning of another.

This section should not be interpreted to mean that the Commission has no policy preference on contract lengths. We stand by Section 69.1805 of the default service policy statement, which provides that long-term contracts should primarily be used to meet the requirements of the Alternative Energy Portfolio Standards Act, and the supply needs of residential and small business customers in the early years of the post-transition period. We do suggest in the policy statement that full requirements or block purchase contracts of one to three years in length, which may be laddered, be part of the portfolio for residential and small business customers for the DSP’s first default service program. We also suggest that the portion of the portfolio that relies on shorter term contracts (e.g., 1 year or less) and the spot market be gradually increased with time. This procurement
approach is consistent with Competition Act standard that energy be acquired at prevailing market prices.

In conclusion, we are generally skeptical of the DSP’s ability to beat the market over periods of time greater than one year. Incumbent EDCs have simply not provided any real record in this or other default service proceedings to show that they can anticipate changes in market prices, and take advantage of this information to obtain consistently lower prices through long-term contracts compared to short-term and spot market purchases. Wholesale market prices are very sensitive to factors completely beyond the control of DSPs, suppliers and regulators, including weather, global energy demand, and war. This is one of the key reasons we are discouraging the use of bilateral contracts in the acquisition of default service supply. We believe customers will save more money as DSPs gradually increase their utilization of short-term fixed price contracts and spot market products, and what data we do have supports this premise. For example, Direct Energy cited to a report in its reply comments that Duquesne’s residential customers would have saved $75 million during the first two years of its “POLR III” plan if they had been on monthly priced service.27 Small commercial customers would have realized savings of $28 million over the first 23 months of the POLR III plan. Id.

We are sensitive to the concerns of parties regarding price volatility, and the need for customers to become accustomed to market pricing and the regular adjustment of rates. Therefore we do support reliance on longer-term, fixed price products in the years immediately following the expiration of rate caps.

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27 Intelometry Inc., Power Price Report, Pittsburgh Market (Duquesne Light) 1/1/05 through 11/30/06, December 2006. Direct Energy also provided evidence in a separate proceeding, which they refer to in their reply comments, that the PJM monthly clearing price in the PJM zone was less than the PPL tariff price for residential customers in at least 32 out of 49 months between 2002 and 2005. Direct Energy Reply Comments, pg. 3. Direct Energy asserts that PECO’s small commercial customers would have saved approximately $1.1 billion off their tariff rate between January 1, 2002, and November 30, 2005, through the use of a monthly pricing mechanism. Intelometry Inc., Power Price Report, Philadelphia Market (PECO) 1/1/02 - 11/30/06, December 2006.
I. § 54.187. Default service rate design and the recovery of reasonable costs

This section has been significantly revised. After reviewing the many comments on this issue from the IRRC and other parties, the Commission concluded that its approach to rate design and cost recovery was too prescriptive. Therefore, this section has been revised to provide more flexibility to DSPs and the Commission to manage the default service obligation. Additional guidelines on rate design and cost-recovery are included in the default service policy statement.

Many commentators believed that the proposed version of 54.187(a) was overly complex, or simply incorrect in its design. The IRRC also had many questions about this section. We agree that this is one of the more technically complex issues of this rulemaking. In the revised Section 54.187(a), the Commission limits its finding to the requirement that the default service rate should represent the sum of all generation and transmission related costs.

In response to the IRRC’s comments on the proposed 54.187(a)(1) and (a)(2), the Commission maintains its position that distribution rates should be examined to ensure that no generation costs remain embedded. The PTC, which is derived from default service rates at a particular point in time, shall be designed to recover all default service costs for an average member of a customer class. The revised 54.187(d) provides that the default service rate may not include any distribution costs, and that EDC distribution rates be reduced to reflect embedded costs reallocated to the generation component of the PTC. However, we believe that this issue will require considerable study and additional policy development. Therefore we have moved much of the detail on this issue to the final policy statement on default service, where we identify what we believe to be the appropriate cost elements for default service. We expect that each EDC will have its
distribution rates addressed in a separate proceeding to finally resolve this issue. This may involve the performance of new cost of service studies for each EDC, as suggested by the IRRC. The Commission may also make use of a collaborative process to develop uniform standards on embedded costs to be applied to each EDC.

In response to the IRRC and other parties’ comments to 54.187(b), (c) and (d), we have removed the language mandating fixed rate options and hourly rates for certain customer classes. The associated definitions have been deleted from 54.182. The new Section 54.187(b) now provides that each customer will have a single rate option, which will be described as the PTC. The PTC will be a new, separate line item on a monthly bill that represents the sum of all transmission and generation related charges. The PTC will not replace the unbundled generation, distribution, and transmission charges that currently appear on a monthly bill. The use of a PTC will enable customers to make more informed choices regarding whether or not to seek service with an EGS. We intend that customers be educated about the use of the PTC as part of the consumer education initiatives that will be implemented pursuant to the Final Order in the price mitigation proceeding.

In order to provide normal incentives for conservation, and to reflect the actual cost of energy, we have revised Section 54.187(c). The revised language will have the effect of eliminating “declining blocks” from rate schedules. Some EDC rate schedules currently provide that the rate charged per kWh declines once the customer uses a certain amount of electricity in a given month, such as 1000 kW. This provision would require those rate designs for default service to be eliminated.\textsuperscript{28}

Sections 54.187(e) and (f) address the issue of cost reconciliation. Consistent with the comments of the IRRC, Section 54.187(e) has been revised to include a reference to

\textsuperscript{28} In its most recent POLR filing, at Docket P-00072247, Duquesne proposed to eliminate declining blocks and demand charges for all customers by 2010.
the Commission’s alternative energy regulations at Chapter 75. In responding to the IRRC’s concern about reconciliation, we note that the AEPS Act expressly provides that alternative energy costs be recovered through a Section 1307 automatic adjustment clause. See 73 P.S. § 1648.3(a)(3). Cost-recovery mechanisms for alternative energy are also being specifically addressed in a pending rulemaking at Docket L-00060180. As the alternative energy portfolio standard is effectively a component of the default service obligation, these rules necessarily contain cross-references.

In response to the IRRC’s comment to the proposed 54.187(a)(3) and 54.187(d), we do not believe that these rules will hinder the ability of DSP’s to meet their AEPS requirements. The AEPS Act expressly provides that:

(4) (i) An electric distribution company or electric generation supplier shall comply with the applicable requirements of this section by purchasing sufficient alternative energy credits and submitting documentation of compliance to the program administrator.

(ii) For purposes of this subsection, one alternative energy credit shall represent one megawatt hour of qualified alternative electric generation, whether self-generated, purchased along with the electric commodity or separately through a tradable instrument and otherwise meeting the requirements of commission regulations and the program administrator.

73 P.S. §1648.3(e)(4) (Emphasis added). Accordingly, a DSP may meet its portfolio requirements solely with alternative energy credits that have been separated from the energy commodity. Therefore, the use of competitive procurements in combination with automatic adjustment clauses, or hourly priced options, poses no problems for alternative energy compliance. Energy prices or rate options are irrelevant, because the DSP does not have to buy energy to satisfy the requirements of the AEPS Act.

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30 PECO filed a petition with the Commission on March 19, 2007, regarding its AEPS obligations. It proposes to hold several competitive auctions for alternative energy credits only in late 2007 and early 2008. The costs of these credits would be recovered through a Section 1307 automatic adjustment clause after PECO’s generation rate cap
In Section 54.187(f) the Commission provides that a DSP may propose cost-reconciliation of non-alternative energy costs as part of its default service program. The Commission now concludes that reconciliation of default service costs may be necessary, and in fact is more desirable, to enable the DSP to “. . . recover fully all reasonable costs” so that the PTC reflects market prices. 66 Pa.C.S. § 2807(e)(3). If the DSP wishes to utilize a cost reconciliation mechanism, the default service policy statement provides guidelines on this subject. The original Section 54.187(h), which was commented on by the IRRC, and included a prohibition on reconciliation, has therefore been removed.

To respond to the concern of the IRRC regarding reconciliation, we find that parity between EDCs and EGSs can be maintained through the regular adjustment of rates, the gradual increase in spot market products, and the limitation on the use of long-term contracts, and several other measures. With these elements, the default service rate will more closely track the market prices offered by EGSs. The elimination of declining blocks and the use of the PTC will also facilitate competitive choice. We are also exploring a variety of other initiatives through the default service policy statement to facilitate retail choice. Finally, this regulation does not mandate the use of reconciliation. We will be monitoring DSP’s use of reconciliation mechanisms going forward, and to the extent that they are abused, we will decline to approve, or otherwise modify, their use.

Section 54.187(g) requires the DSP to include demand side response and management rates in their default service program if the Commission has mandated that expiration. Petition of PECO Energy Company for Approval of (1) A Process to Procure Alternative Energy Credits During the AEPS Banking Period and (2) A Section 1307 Surcharge And Tariff To Recover AEPS Costs; Docket P-00072260. PECO would bank these credits during its rate cap period and use them satisfy its non-solar photovoltaic Tier I obligations for several reporting periods.

31 This statutory interpretation is codified in the pending rulemaking at Docket L-00060180. The legal challenge to this interpretation filed in the context of the appeal of the Commission’s ruling on Pennsylvania Power Company’s POLR filing at Docket P-00052188 has been withdrawn. See Commonwealth Court Docket 1085 C.D. 2006. We note that in that case, Pennsylvania Power Company made its wholesale suppliers contractually responsible for providing it with sufficient alternative energy credits to meet its portfolio obligation under the AEPS Act for the term of that plan.
such rates be available. The Commission is studying this topic as part of a pending
investigation into conservation, energy efficiency, and demand side response. Consistent with the IRRC’s suggestion, we have included a definition of demand side response and demand side management by reference to an existing definition found at Section 1648.2 of the AEPS Act, 73 P.S. § 1648.2. In response to the IRRC’s question regarding potential hardship for smaller DSPs in offering these programs, this is an area where a waiver may be requested.

The revised Section 54.187(g) allows for the option of an hourly priced rate for residential customers, as recommended by the IRRC in their comment to proposed Section 54.187(b). We are aware that real time pricing pilots have recently been implemented in Illinois for residential customers in response to the expiration of rate caps, and believe that such pilots may also be appropriate in Pennsylvania. A DSP may therefore propose to include an optional, hourly priced rate for residential customers in its default service program. However, we are reluctant to mandate that hourly priced service be offered at this time to all customers. In order for hourly priced service to be offered, EDCs may need to make significant new investments in metering, billing and communication systems. These investments may cost a significant amount of money, and these costs would ultimately be recovered from ratepayers. The Commission needs to carefully consider the costs associated with hourly pricing before mandating that all customers have this option. This is one of a number of issues being studied in our pending investigation on DSR, energy efficiency and conservation.

Sections 54.187(h), (i) and (j) represent major revisions to the rulemaking. Specifically, the Commission finds that the PTC should be adjusted on a regular basis as opposed to remaining fixed for the entire duration of a program. This is consistent with a recommendation made by the IRRC, in its comment to the proposed section 54.187(b),

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that rates have some variability to reflect market prices. This also addresses the IRRC’s
commment to the proposed 54.187(g), that adjustment mechanisms be clearly set forth.
The frequency of this PTC adjustment would be dependent on the customer class.\textsuperscript{33} For
residential and small business customers, rates will be adjusted at least every quarter. For
large business customers, the PTC will be adjusted at least every month. DSPs have the
discretion to propose more frequent adjustments in their program filings, consistent with
the IRRC suggestion that flexibility be allowed for in this area. Accordingly, DSPs may
elect to offer hourly rates to large commercial and industrial customers.

As stated earlier, this approach is similar to our regulation of natural gas supply
costs. The purchased gas cost rate for most natural gas distribution companies is adjusted
quarterly to reflect changes in their incurred costs of supplying customers. 52 Pa. Code §
53.64(i)(5). When wholesale market prices move higher, rates increase. When prices
decline, rates are reduced. Having regular adjustments allows the utility to collect its
costs immediately, avoid and manage cost under recoveries, and not incur additional
costs associated with trying to recover the difference between costs and revenues all at
one time. If gas customer rates were not adjusted quarterly, the annual reconciliation
process could demonstrate larger divergences between costs incurred and revenues
received. Overall costs would be higher, as more interest would need to be paid either by
the utility or customers in reconciling costs and revenues. Pennsylvania’s residential gas
customers, most of whom are also customers of EDCs, are well accustomed to having
their gas rate adjusted quarterly. We expect that retail electric customers can manage
quarterly adjustments as well.

In both this rulemaking and the accompanying policy statement, the Commission
is encouraging DSPs to acquire a portfolio of generation supply products. Rather than
simply procuring all generation at one time for the entire duration of the program, DSPs

\textsuperscript{33} Consistent with suggestions made by the IRRC and other commentators, we are giving the DSP some flexibility in
determining the divisions of customers to preserve existing rate schedules.
should consider a mix of fixed-term and spot market energy purchases, laddered contracts, and the use of both supply and demand resources. The Commission recognizes the risks posed by the practice of procuring all generation supply for the entire duration of a program at a single point in time.

PCLP’s last default service filing is a case in point. PCLP procured all of its default service supply for 2006-2007 through an auction held in October of 2005, approximately two months after Hurricane Katrina severely disrupted wholesale energy markets and the nation’s energy infrastructure. As a result of very high prices in wholesale markets, PCLP’s average customer experienced a total bill increase of about 75% on January 1, 2006, which included a generation rate increase of about 129%. Because all energy was acquired at one point in time, PCLP’s default service rate for the entire two year program was locked in and reflected the market price of the day of the auction. Even though wholesale energy prices retreated substantially from their late 2005 and early 2006 peaks, PCLP’s high default service rate was not reduced.

This is in marked contrast to the experience of retail customers of PCLP’s parent company, Orange & Rockland Utilities, Inc. (“O&R”), whose territory lies just across the state line in New York. For the same time period covered by PCLP’s plan, Orange & Rockland was utilizing a portfolio approach, whereby it was acquiring supply through a mix of fixed-term contracts and spot market energy purchases. The costs O&R incurred to serve its default customers therefore changed over time in response to changes in wholesale market prices. O&R’s retail customers are charged a “market supply charge” which changes every month. While O&R’s market supply charge increased in October of 2005, it declined in subsequent months as wholesale energy prices retreated.34 PCLP’s customers did not benefit from the decline in wholesale energy prices as their rate was set in advance for a two year period.

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34 O&R’s price to compare for the last few years can be viewed at http://www.oru.com/energyandsafety/energychoice/newyork/orupricetocompare.html
In this rulemaking and the default service policy statement, the Commission is encouraging DSPs to take an approach similar to O&R’s. This would include the use of multiple fixed-term contracts and spot market energy purchases. Laddering of contracts should also be considered. This is a departure from some of the recent POLR filings where the entire supply was provided pursuant to one or more fixed-term contracts. A small step was taken in this direction in the recent Pennsylvania Power Company default service plan, where energy was procured for a 17 month period in two separate auctions.

In arriving at this decision, we find that there is simply too much risk associated with procuring all supply at a fixed rate for the entire duration of the program. When a price is locked in and wholesale rates move lower, customers will experience what PCLP customers have dealt with over the past few years. When wholesale energy prices increase above a fixed rate, customers may experience sharp, unplanned increases when the program expires (e.g., the experience of many customers in this region, including Maryland, when generation rate caps set during a time of lower wholesale energy prices expired).

Fixed default service rates for prolonged periods are also detrimental to the development of retail markets in Pennsylvania. For example, EGSs have simply not been able to compete with the below market rates offered by EDCs during the generation rate cap period. Customer choice is largely nonexistent outside the territory of Duquesne, the only large EDC whose generation rate cap has expired. A PTC that is fixed for long periods of time, and that does not adjust to changes in wholesale energy prices, will stifle competition. We believe customers will receive the lowest rates when multiple EGSs are competing for their business, as is the case for any good or service that consumers need.

35 The experience of Duquesne shows that retail markets can work. Duquesne’s territory has the highest rate of customer choice in Pennsylvania. See http://www.oca.state.pa.us/Industry/Electric/elecstats/instat.htm. Its overall retail electric rates remain 15% below what they were when the Competition Act was passed in 1996. http://www.puc.state.pa.us/general/pdf/ThomasStmt_OSA0203_081904.pdf.
If DSP rates are fixed at below market prices for prolonged periods, EGSs will not be able to make price attractive offerings to customers. Instead, customers will be left with no readily available alternative to the DSP’s rate when it eventually is adjusted to reflect the market price. The PCLP experience will be repeated again and again. If EGSs know that the PTC will be adjusted consistent with the DSP’s incurred costs as wholesale markets change, they will invest more time and money in establishing a presence in Pennsylvania, and marketing their service to customers. Customers will then have greater opportunity to choose among suppliers and realize savings.

This is not to say that customers should be deprived of the opportunity to obtain a fixed price for generation service. We have concluded that the public interest will be served, in the form of lower rates over the long term, if the default service rate is regularly adjusted to reflect changes in default service costs as they occur. In this regulatory environment, EGSs will respond by entering the market in greater numbers, and if there is a significant demand for these types of rates, offer them.36 We caution, however, that such price certainty does not come without increased costs for the customer. A retail rate that cannot be adjusted over a significant period of time in response to changes in wholesale energy markets will reflect a risk premium, whether offered by a DSP or an EGS.

Many comments were filed in response to this section of the ANOFR on the subject of declining blocks, cost-reconciliation, customer groupings and rate design. The Commission has made a number of changes to the ANOFR in response to these comments.

36 In support of this assertion we refer to the OCA’s residential gas customer shopping guide, dated January 5, 2007. One year, fixed price contracts for residential customers are currently available in the service territories of Columbia Gas, Dominion Peoples, and UGI Utilities, Inc. – Gas Division.
The Price-to-Compare

In response to comments to the ANOFR, we are clarifying the use of the PTC. This is a new line item that represents the sum of generation and transmission related charges. However, transmission and generation related charges should still be included on the monthly utility bill as separate line items. In response to a comment from Constellation regarding taxes, we wish to confirm that sales tax should not be included in the PTC.

Declining Blocks and Demand Charges

The Commission received comments both for and against the elimination of declining blocks in response to the ANOFR. Some parties, such as the OCA, warned that their abrupt elimination may lead to rate shock for certain customer classes. Others, like IECPA, Allegheny, US Steel, and PECO, believe that demand charges and/or declining blocks are an appropriate element of rate design.

In addressing these comments, we will review UGI’s most recent default service plan. On April 17, 2006, UGI filed a petition with the Commission to establish default service rates for the 2007-2009 period. After the proceeding was initiated, UGI and several other interested parties initiated settlement discussions. A Joint Petition for Settlement was filed with the Commission on June 1, 2006. The signatories included UGI, the OCA, the OSBA and Constellation.

Under the terms of the settlement, UGI agreed to phase out some declining block rates and generation demand charges over a three year period. UGI attached the testimony of David C. Beasten, Director of Electric Power Supply and Rates, in support of the settlement. On the topic of declining blocks, Mr. Beasten testified:
When one purchases energy in the market, one generally pays the same price for all the energy purchased. Having declining block rates for generation service thus gives a false price signal to customers.

Mr. Beasten explained that immediate elimination of these rates could result in rate shock for some customers. Accordingly, UGI proposed to phase out these rates over three years. The Commission accepted this proposal, and approved the Joint Settlement. *Petition of UGI Utilities, Inc. – Electric Division for Approval to Implement 2007-2009 Default Service Tariff Provisions on One Day’s Advance Notice*, Docket No. P-00062212 (Order entered June 22, 2006).

We still agree with Mr. Beasten’s testimony that declining block rates for default service gives false price signals to customers. This false price signal discourages energy conservation and complicates retail choice. Therefore, the requirement to eliminate all declining block rates will remain in the final version of this rule.

However, we do accept the argument of IECPA, Allegheny, US Steel and PECO that generation and transmission demand charges may be appropriate in some circumstances for large commercial and industrial customers. Accordingly, this rule does not include a blanket prohibition on generation and transmission demand charges. DSPs may propose demand charges that are rationally related to the costs of providing service to large commercial and industrial customers. Incumbent EDCs should not assume that the Commission will approve the demand charges currently appearing in their tariffs. We agree with the reply comments of the OSBA that the current demand charges are a legacy from the pre-restructuring era, and do not reflect the actual costs of serving these customers in today’s markets. DSPs should be prepared to include strong evidence in their default service program filings that supports the design and cost basis of any proposed demand charges.
The UGI Joint Settlement is also appropriate for consideration in the context of price increase mitigation. The Commission agrees with the OCA that the immediate termination of declining block rates and generation demand charges could lead to rate shock for certain customers. Therefore, we will apply the rate change mitigation provision of the default service policy statement to this issue. If a DSP finds that the elimination of declining blocks or demand charges would lead to an increase of 25% or more for any customer class, it should propose to gradually phase out these design elements through a series of annual adjustments. The length of this adjustment process may vary, depending on the size of the increase to be mitigated. Generally, we believe this can be done within 2-3 years.

Cost Reconciliation

We recognize that the use of a reconciliation mechanism was strongly opposed by some who responded to the ANOFR, who assert that the use of a reconciliation mechanism may harm the development of retail competition. Some, like Dominion, believe that DSPs may use reconciliation to give a false price signal in order to keep retail customers from shopping. The DSP could attempt this by charging a below market PTC and then recovering any under collections, with interest, during an end of the year reconciliation process.

We have given serious consideration to these comments and the potential problems identified. Consistent with the gas cost recovery model, we will provide for asymmetrical interest calculations for under and over collections.\textsuperscript{37} Interest paid to the DSP will be at the legal rate of interest, which is 6%.\textsuperscript{38} The interest rate paid to customers for refunds of over collections shall be 8%. This will serve as a disincentive to price manipulation behavior, and an incentive to acquire energy at prevailing market

\textsuperscript{37} 66 Pa.C.S. § 1307(f)(5).
\textsuperscript{38} 41 P.S. § 202.
prices. The Commission will also closely monitor the use of reconciliation mechanisms by DSPs.

We remind DSPs that the discretion afforded them by this regulation is not an invitation to acquire all energy through a handful of multi-year full requirements contracts and then passively observe costs and revenues significantly diverge in response to wholesale market events, customer migration, etc. Such conduct would not be consistent with the acquisition of energy at “prevailing market prices” or the incurrence of “reasonable costs.” 66 Pa.C.S. § 2807(e)(3).

Rather, we are giving DSPs the tools to proactively manage their default service obligation. A DSP may minimize the risk of under collection through the regular adjustment of rates. Additionally, we believe the risk of seasonal gaming will be greatly reduced when the PTC is adjusted on a regular basis in response to the change in composition of the portfolio. This is why we have directed that the PTC be adjusted at least every quarter or month, depending on customer size. This approach ensures full customer choice but protects DSPs from seasonal gaming and under recovery of costs.

To the extent that a DSP is concerned that it lacks the expertise or resources to proactively manage short-term purchases, they are free to retain the services of other parties and include these costs in their rates. For example, a DSP could outsource the management of its spot and short-term energy portfolio. As stated earlier in this order, this regulation also allows DSPs to coordinate their procurements of default service supply. Smaller DSPs are strongly encouraged to consider pooling their resources in the management of the default service obligation, and may request waivers from provisions that are too burdensome.

Additionally, at the suggestion of IECPA and others, we have revised this section to clearly state that the use of a reconciliation mechanism will be subject to annual review.
and audit, consistent with Sections 1307(d) and (e) of the Public Utility Code. The review of alternative energy and non-alternative energy costs recovered through an automatic adjustment clause should be addressed in the same proceeding in order to reduce administrative costs to the parties. The public notice and hearing provisions of Section 1307(e) will apply to these filings.

Customer Groupings and Frequency of Rate Changes

Some parties have objected to the frequency of rate changes for customers, asserting that this will produce harmful volatility in rates. We simply disagree with this analysis. We cite to the experience of the State of Maryland, which has already transitioned to market based rates, as referenced by Strategic and NEM in their comments to the ANOFR:

The Commission concurs with the parties that rate stability is an important public policy goal generally, and particularly with respect to SOS. Recent experience suggests that longer term fixed prices do not contribute to that goal; indeed they create a false sense of complacency that costs are in fact stable, followed by the painful transition when rates are finally adjusted to reflect current costs … The upshot is that frequent, albeit small rate changes, are a better vehicle for insuring relative rate stability (and a more gradual reflecting of changes in current market prices) rather than longer periods of frozen rates, followed by rate shock.

Maryland Public Service Commission, Case No. 9056, Investigation into Default Service For Type II Standard Offer Service Customers, Order 81019, Issued August 19, 2006.

In response to those suppliers who feel that quarterly and monthly changes in rates are too infrequent, we remind them that the regulation sets the minimum frequency of change. For example, DSPs may propose more frequent changes in rates, such as hourly priced service, for their larger commercial and industrial customers.
In response to the comments of the IRRC on this issue to the proposed Section 54.187(c), the Commission wishes to emphasize that the regulations allow DSPs the discretion to propose alternative groupings of retail customers for good cause. For example, Duquesne may propose to continue to offer hourly priced service to all customers at or above 300 kw. DSPs may also separate residential and small business customers for procurement purposes, as recommended by the OCA.

We recognize that the number and distribution of customers across classes varies significantly from territory to territory. For example, it may be necessary to combine the customer classes of smaller DSPs in order to develop tranches of sufficient size for competitive auctions. Alternatively, individual tranches may be stratified into residential and business customer segments when there are insufficient customers to create separate tranches for the different customer classes. Reasonable, alternative groupings of customers may be proposed for our consideration, consistent with the suggestion of the IRRC.

**Single Rate Option**

Some parties believe that the Commission is unduly restricting the rate options available to customers in this rulemaking. It has been suggested that Section 2806(h) of the Public Utility Code, 66 Pa.C.S. § 2806(h), be used in the context of default service to provide flexible pricing options to individual customers. DSPs may include proposals for flexible rates in their default service programs. However, these programs may increase the complexity and costs of providing basic default service. Additionally, these proposals must comply with the Public Utility Code and recent precedent regarding reasonable differences in rates between customer classes. 66 Pa.C.S. § 1304; *Lloyd v. Pa. Public Utility Commission*, 904 A.2d 1010 (Pa. Cmwlth 2006).
The Commission will keep an open mind on the appropriateness of renewable energy default service products, such as PECO’s “Wind Tariff.”\(^{39}\) However, we observe that two EGSs are currently offering “green” energy products to residential customers in PECO’s service territory. Additionally, default service supply will begin to incorporate a gradually increasing renewable energy component with the expiration of the rate cap, consistent with the requirements of the AEPS Act. PECO may propose the continuation of this rate in its first default service program and submit evidence of how this service is consistent with a “provider of last resort” role in the post-transition period.

Finally, we are revising Section 54.187(k) in response to a comment made by the OCA to the ANOFR. The OCA recommends that a DSP be required to first use any collateral owed by a wholesale supplier pursuant to an energy contract in the event of a default. Only after this collateral was fully exhausted could the DSP seek to recover the incremental costs of a default from customers. We agree with this recommendation and have revised Section 54.187(k) to require DSPs to first seek recovery under their “contract terms with the default supplier.”

**J. § 54.188. Commission review of default programs and rates**

Section 54.188 has been revised to reflect the introduction of new terms such as default service program, etc. The review period standard has been moved from the Section 54.186(f)(2) to 54.188(d) in this version. Some parties commented that the proposed review period was too long and open-ended, and may detrimentally affect the prices bid by suppliers. The IRRC, in comments to the prior version of 54.186(f)(2)

\(^{39}\) The Commission held that offering and marketing this tariff was permissible under the terms of the settlement agreement relating to the establishment of the Exelon Corporation and its merger with the Unicom Corporation. However, the Commission did not make a final decision on the availability or marketing of this tariff in the context of post-transition period default service. *Green Mountain Energy Company v. PECO Energy Company*, Docket R-00016938C0001 (Order entered July 18, 2003).
recommended reducing the review period from “no less than” to “no more than” 3 business days. The Commission agrees with these comments, and believes the period can be reduced. Accordingly, the Commission is reducing its review period from “no less than three business days” to no more than “one business day.” The Commission provides additional guidelines on this issue in the default service policy statement.

We have clarified Section 54.188(d) to state that while the result of a solicitation may be deemed approved if not formally rejected within one business day, this does not represent the end of the Commission’s oversight. Should information subsequently come to the attention of the Commission that the DSP failed to adhere to the approved plan, that the DSP disclosed confidential information to an affiliate, or that one or more bidders engaged in fraud, collusion, bid rigging, price fixing or other unlawful acts the Commission would investigate and seek appropriate remedies.

We agree with the IRRC that procurement plans should be reviewed to ensure that their design will result in reliable supply of electric at market prices with the incurrence of reasonable costs. The default service policy statement includes guidelines for DSPs intended to help achieve this goal.

We are declining to adopt the IRRC and some other commentators’ suggestion that we lengthen the default service case timeline from six to nine months. The Commission has adjudicated several default service cases, including the Pennsylvania Power Company’s most recent filing, within a six month period. We believe that with the issuance of final regulations, greater consistency among filings, and the experience that will come with each case, the Commission, DSPs, and other parties will become more efficient in the filing and review of default service programs. However, we will adjust the standard to seven months, and this final form regulation reflects this change. This is the same time period for which the Commission may suspend a tariff in the context of requests for general rate increase. 66 Pa.C.S. § 1308(d). Where more time is
truly necessary, particularly with initial filings, the DSP can petition for a waiver or modification of the seven month standard pursuant to 52 Pa. Code § 5.43.

Section 54.188(e) provides more structure for the review and approval of the initial rates that will take effect at the beginning of a default service program. The revised regulations establish a standard that should result in customers receiving notice of new rates within a reasonable period of time, and more opportunity to consider other options, including service with an EGS.

Section 54.188(f) now addresses standards for tariff filings required by our decision to require regular adjustment of the PTC. Section 54.188(g) has been eliminated as unnecessary and duplicative. A provision for the waiver of Commission regulations is already in place at 52 Pa. Code § 5.43.

In response to comments by UGI and others to the ANOFR, we are revising Section 54.188(d) to state that we will not conduct an after the fact prudency review of purchases made consistent with a Commission approved default service plan. We are also revising this section, based on a comment from FirstEnergy, to observe that the Commission approval is not required for individual spot market purchases made pursuant to a Commission approved procurement plan. The Commission will study the DSPs overall spot market acquisition strategy in its review of the default service program. However, as noted above, a DSP’s disclosure of confidential information to an affiliate or fraud, collusion, bid rigging or price manipulation by suppliers would be subject to Commission investigation and appropriate remedial action.

Section 54.188(e) has been clarified at the suggestion of the OCA to require that customers be given initial notice of the filing of the default service program. This notice is modeled on the provision that applies to natural gas distribution companies utilizing Section 1307(f) of the Public Utility Code.
In response to IRRC’s comment on this section, we note that the proposed Section 54.188(g) has been deleted. Requests for waivers must now be included in the default service program, consistent with the new 54.185(f). The phrase “and other applicable laws” no longer appears in this context.

K. § 54.189. Default Service Customers and the Standards for Transferring Customer Accounts to Default Service Providers

We agree with the IRRC that limitations on choice are inappropriate and contrary to the provisions of the Competition Act. We find that by providing for regular rate adjustments that track changes in market prices, any incentives to game the system through frequent changes in suppliers is greatly reduced. References to regulatory provisions have been added for clarity.

In response to comments by the OCA and IECPA, the Commission is making several edits to this section. Customers who are taking service with an EGS do not need to “apply” for default service. These customers should have already gone through an application process with an EDC when they first signed up for electric utility service. Since the incumbent EDC is currently the DSP in all service territories, customers who are shopping are still EDC customers for purposes of distribution and transmission service. Accordingly, they do not need to apply again, and potentially be required to pay onerous security deposits, to return to the DSP from an EGS.40

40 Several parties commented on PECO commercial customers currently receiving generation service from an EGS as a consequence of PECO’s Market Share Threshold program. These customers have the right to change their generation service provider at any time. However, the Commission will not, and PECO should not, automatically reassign these customers to default service upon the expiration of the generation rate cap.
CONCLUSION

The Commission thanks the parties for their comments and participation in this proceeding. Given the high level of public interest in this matter, we offer the following information on the next steps in this rulemaking procedure. Upon the entry of this Final Order, the Commission will prepare this rule for delivery to the General Assembly and the IRRC. If the rule is approved by the IRRC, it will be forwarded to the Pennsylvania Attorney General for review as to form and legality. The Pennsylvania Attorney General has thirty days to review this final form rule. If not rejected by the Pennsylvania Attorney General, the rule will become legally effective upon publication in the Pennsylvania Bulletin. This process should take approximately two to three months.

Accordingly, under 66 Pa. C.S. §§ 501, 2807(c)(2), and the Commonwealth Documents Law, 45 P.S. §§ 1201 et seq., and the regulations promulgated hereunder at 1 Pa. Code §§ 7.1, 7.2, and 7.5, the Commission proposes adoption of the final regulations pertaining to the obligations of EDCs to connect, deliver and acquire electricity at the conclusion of the transition period, as noted and set forth in Annex A; THEREFORE,

IT IS ORDERED:

1. That this docket adopts the final regulations in Annex A.

2. That the Secretary shall submit this order and Annex A to the Office of Attorney General for approval as to legality.

3. That the Secretary shall submit this order and Annex A to the Governor’s Budget Office for review of fiscal impact.
4. That the Secretary shall submit this order and Annex A for review by the designated standing committees of both houses of the General Assembly, and for review and approval by the Independent Regulatory Review Commission.

5. That the Secretary shall deposit this order and Annex A with the Legislative Reference Bureau for publication in the *Pennsylvania Bulletin*.

6. That regulations embodied in Annex A shall become effective upon publication in the *Pennsylvania Bulletin*.

7. That the contact person for this rulemaking is Shane M. Rooney. Alternate formats of this document are available to persons with disabilities and may be obtained by contacting Sherri Delbiondo, Regulatory Coordinator, Law Bureau, 717-772-4597.

BY THE COMMISSION,

James J. McNulty,
Secretary

(SEAL)
ORDER ADOPTED: May 10, 2007
ORDER ENTERED: May 10, 2007
ANNEX A

TITLE 52. PUBLIC UTILITIES

PART I. PUBLIC UTILITY COMMISSION

Subpart C. FIXED SERVICE UTILITIES

CHAPTER 54. ELECTRICITY GENERATION

CUSTOMER CHOICE

Subchapter A. CUSTOMER INFORMATION

* * * * *

§ 54.4. Bill format for residential and small business customers.

* * * * *

(b) The following requirements apply only to the extent to which an entity has responsibility for billing customers, to the extent that the charges are applicable. The default service provider will be considered to be an EGS for the purposes of this section. Duplication of billing for the same or identical charges by both the EDC and EGS is not permitted.

* * * * *

§ 54.5. Disclosure statement for residential and small business customers

* * * * *

(b) The EGS shall provide the customer written disclosure of the terms of service at no charge whenever:

* * * * *

(3) Service commences from a default service provider.
(c) The contract's terms of service shall be disclosed, including the following terms and conditions, if applicable:

* * * * *

(9) The name and telephone number of the [provider of last resort] default service provider.

* * * * *

(h) If the [provider of last resort] default service provider changes, the new [provider of last resort] default service provider shall notify customers of that change, and shall provide customers with their name, address, telephone number and Internet address, if available.

§ 54.6. Request for information about generation supply.

(a) EGSs shall respond to reasonable requests made by consumers for information concerning generation energy sources.

* * * * *

(2) The [provider of last resort] default service provider shall file at the Commission the annual licensing report as required by the Commission’s licensing regulations in this chapter and shall otherwise comply with paragraph (1).
Subchapter B. ELECTRIC GENERATION SUPPLIER LICENSING

§ 54.31. Definitions.

The following words and terms, when used in this subchapter, have the following meanings, unless the context clearly indicate otherwise.

* * * *

Default service provider – The incumbent EDC within a certificated service territory or a Commission approved alternative default service provider SUPPLIER OF ELECTRIC GENERATION.

[Provider of last resort – A supplier approved by the Commission under section 2807(e)(3) of the code (relating to duties of electric distribution companies) to provide generation service to customers who contracted for electricity that was not delivered, or who did not select an alternative electric generation supplier, or who are not eligible to obtain competitive energy supply, or who return to the provider of last resort after having obtained competitive energy supply.]

* * * *

§ 54.32. Application process.

* * * *

(h) An EDC acting within its certificated service territory as a [provider of last resort] default service provider is not required to obtain a license.

* * * *
§ 54.41. Transfer or abandonment of license.

* * * * *

(b) A licensee may not abandon service without providing 90 days prior written notice to the Commission, the licensee's customers, the affected distribution utilities and [providers of last resort] default service providers prior to the abandonment of service. The licensee shall provide individual notice to its customers with each billing, in each of the three billing cycles preceding the effective date of the abandonment.

* * * * *

Subchapter E. COMPETITIVE SAFEGUARDS

* * * * *

§ 54.123. Transfer of customers to default service.

The following standards apply to the transfer of a retail customer’s electric generation service from an EGS to a default service provider within the meaning of § 54.182 (relating to definitions):

(1) An EGS may not transfer a retail customer from its electric generation service to the default service provider without the consent of the default service provider, except in the following situations:

(i) Upon Commission approval of the abandonment, suspension or revocation of an EGS license, consistent with §§ 54.41 and 54.42 (relating to transfer or abandonment of license and license suspension; license revocation).

(ii) Upon nonpayment by a retail customer for services rendered by the EGS.
(iii) To correct an unauthorized or inadvertent switch of a retail customer’s account from default service to an alternative EGS’s service, CONSISTENT WITH 52 PA. CODE § 57.177 (PERTAINING TO CUSTOMER DISPUTE PROCEDURES).

(iv) Upon the normal expiration of contracts that are not structured in a way to exploit seasonal variations in market prices for electric generation service.

(2) An EGS may initiate transfers in the above situations through standard electronic data interchange protocols.

(3) An EGS may not initiate or encourage transfers of service to a default service provider from the EGS to exploit seasonal variations in market prices for electric generation services.

(4) The Commission may impose a penalty for every retail customer transferred to default service in violation of this section, consistent with 66 Pa.C.S. §§ 3301-3316 (relating to violations and penalties).

Subchapter G. DEFAULT SERVICE

§ 54.181. Purpose.

This subchapter implements 66 Pa.C.S. § 2807(e) (relating to duties of electric distribution companies), pertaining to an EDC’s obligation to serve retail customers at the conclusion of the restructuring transition period. The provisions in this subchapter ensure that retail customers who do not choose an alternative EGS, or who contract for electric energy that is not delivered, have access to generation supply at prevailing market prices. The EDC OR OTHER APPROVED ENTITY shall fully recover all reasonable costs for acting as a default service provider of electric generation supply to all retail customers in its certificated distribution territory.
§ 54.182. Definitions.

The following words and terms, when used in this subchapter, have the following meanings, unless the context clearly indicates otherwise:

*Alternative energy portfolio standards* – A requirement that a certain percentage of electric energy sold to retail customers in the Commonwealth BY EDCS AND EGSS be derived from alternative energy sources, as defined in the Alternative Energy Portfolio Standards Act, (73 P.S. §§ 1647.1 – 1647.78).


*Competitive procurement BID SOLICITATION process* – A fair, transparent, and non-discriminatory process by which a default service provider acquires AWARDS CONTRACTS FOR electric generation supply to serve its default service customers through a bid solicitation process QUALIFIED SUPPLIERS WHO SUBMIT THE LOWEST BIDS.

*Default service* –

(i) Electric generation service provided by a default service provider to a retail electric customer who does not choose an alternative EGS or who contracts for electric energy and it is not delivered.

(ii) Electric generation service provided pursuant to a Commission approved default service plan

ELECTRIC GENERATION SUPPLY SERVICE PROVIDED PURSUANT TO A DEFAULT SERVICE PROGRAM TO A RETAIL ELECTRIC CUSTOMER NOT RECEIVING SERVICE FROM AN EGS.

*Default service implementation plan* – A filing submitted by a default service provider to the Commission that identifies the means for procuring generation supply for default service customers at prevailing market rates, the reasonable costs associated with default service, and all other necessary terms and conditions of service THE SCHEDULE OF COMPETITIVE BID SOLICITATIONS AND SPOT MARKET ENERGY PURCHASES, TECHNICAL REQUIREMENTS, AND RELATED FORMS AND AGREEMENTS.
DEFAULT SERVICE PROCUREMENT PLAN – THE ELECTRIC GENERATION SUPPLY ACQUISITION STRATEGY A DSP WILL USE IN SATISFYING ITS DEFAULT SERVICE OBLIGATIONS, INCLUDING THE MANNER OF COMPLIANCE WITH THE ALTERNATIVE ENERGY PORTFOLIO STANDARDS REQUIREMENT.

DEFAULT SERVICE PROGRAM – A FILING SUBMITTED TO THE COMMISSION BY A DSP THAT IDENTIFIES A PROCUREMENT PLAN, AN IMPLEMENTATION PLAN, A RATE DESIGN TO RECOVER ALL REASONABLE COSTS, AND OTHER ELEMENTS IDENTIFIED AT § 54.185.

DEFAULT SERVICE RATE – THE RATE BILLED TO A DEFAULT SERVICE CUSTOMER RESULTING FROM COMPLIANCE WITH A COMMISSION APPROVED DEFAULT SERVICE PROGRAM.

DSP – Default service provider – The incumbent EDC within a certificated service territory or a Commission approved alternative default service provider SUPPLIER OF ELECTRIC GENERATION SERVICE.

EDC – Electric Distribution Company – The term has the same meaning as defined in 66 Pa.C.S. § 2803 (relating to definitions).

EGS – Electric Generation Supplier – The term has the same meaning as defined in 66 Pa.C.S. § 2803.


Fixed rate option – A default service price that is set in advance for the entire term of the default service implementation plan that may include seasonal differences.

Hourly priced service – A default service price where the energy component of the generation supply charge is based on the RTO or ISO’s LMP for energy, or other similar mechanism.

ISO – A FERC-approved independent transmission system operator.

LMP – Locational marginal pricing – A pricing mechanism used by some RTOs and ISOs, as defined in their FERC approved tariffs.
MAXIMUM REGISTERED PEAK LOAD - THE HIGHEST LEVEL OF DEMAND FOR A PARTICULAR CUSTOMER, BASED ON THE PJM INTERCONNECTION, LLC, PEAK LOAD CONTRIBUTION STANDARD, OR ITS EQUIVALENT, AND AS MAY BE FURTHER DEFINED BY THE EDC TARIFF IN A PARTICULAR SERVICE TERRITORY.

PTC – PRICE-TO-COMPARE – A LINE ITEM THAT APPEARS ON A RETAIL CUSTOMER’S MONTHLY BILL FOR DEFAULT SERVICE. THE PTC IS EQUAL TO THE SUM OF ALL UNBUNDLED GENERATION AND TRANSMISSION RELATED CHARGES TO A DEFAULT SERVICE CUSTOMER FOR THAT MONTH OF SERVICE.

Prevailing market price – (i) The price of electric generation supply for a term of service realized through a default service provider’s implementation of and compliance with a Commission approved default service implementation plan.

(ii) The price of electric generation supply in the RTO or ISO administered energy markets in whose control area default service is being provided, acquired pursuant to the conditions specified in §§54.186(g), 54.187(i) or 54.188(e). THE PRICE THAT IS AVAILABLE IN THE WHOLESALE MARKET AT PARTICULAR POINTS IN TIME FOR ELECTRIC GENERATION SUPPLY.

Replacement procurement process – A Commission approved process, submitted as part of the default service implementation plan, which provides for the acquisition of generation supply in the event that a supplier fails to deliver generation contracted for under the terms of a competitive procurement process.

Retail customer or retail electric customer – These terms shall have the same meaning as defined in 66 Pa.C.S. § 2803.

RTO – Regional transmission organization – A FERC-approved regional transmission organization.

SPOT MARKET ENERGY PURCHASE – THE PURCHASE OF AN ELECTRIC GENERATION SUPPLY PRODUCT IN A FERC-APPROVED REAL TIME OR DAY AHEAD ENERGY MARKET.
§ 54.183. Default service provider.

(a) The default service provider DSP shall be the incumbent EDC in each certificated service territory, except as provided for under subsection (b).

(b) THE DSP MAY BE CHANGED BY ONE OF THE FOLLOWING PROCESSES:

(1) An EDC may petition the Commission to be relieved of the default service obligation.

(2) AN EGS MAY PETITION THE COMMISSION TO BE ASSIGNED THE DEFAULT SERVICE ROLE FOR A PARTICULAR EDC SERVICE TERRITORY.

(3) In the alternative, the THE Commission may propose through its own motion that an EDC be relieved of the default service obligation. The Commission may approve those request if it is in the public interest. In such circumstances, the Commission will announce through an order a competitive process to determine the alternative default service provider, which may be either an EDC or licensed EGS.

(C) THE COMMISSION MAY REASSIGN THE DEFAULT SERVICE OBLIGATION FOR THE ENTIRE SERVICE TERRITORY, OR FOR SPECIFIC CUSTOMER CLASSES, TO ONE OR MORE ALTERNATIVE DSPS WHEN IT FINDS IT TO BE NECESSARY FOR THE ACCOMMODATION, SAFETY AND CONVENIENCE OF THE PUBLIC. A FINDING WOULD INCLUDE AN EVALUATION OF THE INCUMBENT EDC’S OPERATIONAL AND FINANCIAL FITNESS TO SERVE RETAIL CUSTOMERS, AND ITS ABILITY TO PROVIDE DEFAULT SERVICE UNDER REASONABLE RATES AND CONDITIONS. IN THESE CIRCUMSTANCES, THE COMMISSION WILL ANNOUNCE, THROUGH AN ORDER, A COMPETITIVE PROCESS TO DETERMINE THE ALTERNATIVE DSP.
When the Commission finds that an EDC should be relieved of the default service obligation, the competitive process for the replacement of the default service provider shall be as follows:

1. Any EDC or EGS, AN ENTITY that wishes to be considered for the role of the alternative default service provider DSP shall apply for a certificate of public convenience, consistent with 66 Pa.C.S. 1101—1103 (relating to organization of public utilities and beginning of service; enumeration of acts requiring certificate; and procedure to obtain certificates of public convenience) FILE A PETITION PURSUANT TO 66 PA.C.S. § 2807(E)(3).

2. Applicants PETITIONERS shall demonstrate their operational and financial fitness to serve and their ability to comply with Commission regulations, orders and applicable laws pertaining to public utility service.

3. If no applicant PETITIONER can meet this standard, the incumbent EDC will SHALL be required to continue the provision of default service.

4. If one or more applicants PETITIONERS meets the standard provided in paragraph (2), the Commission will approve a certificate of public convenience to act as a default service provider to the applicant best able to fulfill the obligation APPROVE THE DSP BEST ABLE TO FULFILL THE OBLIGATION IN A SAFE, COST-EFFECTIVE, AND EFFICIENT MANNER, CONSISTENT WITH 66 PA.C.S. §§ 1103, 1501, AND 2807(E) (RELATING TO PROCEDURES TO OBTAIN CERTIFICATES OF PUBLIC CONVENIENCE; CHARACTER OF SERVICE AND FACILITIES; DUTIES OF ELECTRIC DISTRIBUTION COMPANIES).

5. An EGS that is granted a certificate of public convenience to act as an alternative default service provider will be considered a public utility within the meaning of 66 Pa.C.S. §102 (relating to definitions) A PETITIONER APPROVED TO ACT AS AN ALTERNATIVE DSP SHALL COMPLY WITH APPLICABLE PROVISIONS OF THE PUBLIC UTILITY CODE.
§ 54.184. Default service provider obligations.

(a) A default service provider DSP shall be responsible for the reliable provision of default service to retail customers who are not receiving generation services from an alternative EGS within the certificated territory of the EDC that it serves OR WHOSE ALTERNATIVE EGS HAS FAILED TO DELIVER ELECTRIC ENERGY.

(b) A default service provider DSP shall comply with applicable Commission regulations and orders THE PUBLIC UTILITY CODE, 66 PA.C.S. § 101, ET SEQ., AND § 1.1, ET SEQ. to the extent that the obligations are not modified by this subchapter OR WAIVED PURSUANT TO § 5.43 (PERTAINING TO WAIVER OF COMMISSION REGULATIONS).

(c) A default service provider DSP shall continue the universal service AND ENERGY CONSERVATION program in effect in the EDC’s certificated service territory or implement, subject to Commission approval, similar programs consistent with the 66 Pa.C.S. §§ 2801-2812 (relating to Electricity Generation Customer Choice and Competition Act). THE COMMISSION WILL DETERMINE THE ALLOCATION OF THESE RESPONSIBILITIES BETWEEN AN EDC AND AN ALTERNATIVE DSP WHEN AN EDC IS RELIEVED OF ITS DSP OBLIGATION.

§ 54.185. Default service implementation plans and terms of service PROGRAMS AND PERIODS OF SERVICE.

(a) A default service provider DSP shall file a default service implementation plan PROGRAM with the Commission’s Secretary’s Bureau no later than fifteen 12 months prior to the conclusion of the currently effective default service plan PROGRAM or Commission-approved generation rate cap for that particular EDC service territory, unless the Commission authorizes another filing date. THEREAFTER, THE DSP
SHALL FILE ITS PROGRAMS CONSISTENT WITH SCHEDULES IDENTIFIED BY THE COMMISSION.

(b) Default service implementation plans PROGRAMS must comply with Commission regulations pertaining to documentary filings AT § 1.1, ET SEQ.

(PERTAINING TO RULES OF ADMINISTRATIVE PRACTICE AND PROCEDURE), except when modified by this subchapter. The default service provider DSP shall serve copies of the default service implementation plan PROGRAM on the Pennsylvania Office of Consumer Advocate, Pennsylvania Office of Small Business Advocate, the Commission’s Office of Trial Staff, EGSS REGISTERED IN THE SERVICE TERRITORY, and the RTO or ISO OTHER ENTITY in whose control area the default service provider DSP is operating. COPIES SHALL BE PROVIDED UPON REQUEST TO OTHER EGSS AND SHALL BE AVAILABLE AT THE DSP’S PUBLIC INTERNET DOMAIN.

(c) A default service implementation plan shall propose a minimum term of service of at least twelve months, or multiple twelve month periods, or for a period necessary to comply with subsection (f). THE FIRST DEFAULT SERVICE PROGRAM SHALL BE FOR A PERIOD OF 2 TO 3 YEARS, OR FOR A PERIOD NECESSARY TO COMPLY WITH § 54.185(D)(4), UNLESS ANOTHER PERIOD IS AUTHORIZED BY THE COMMISSION. SUBSEQUENT PROGRAM TERMS WILL BE DETERMINED BY THE COMMISSION.

(d) A default service implementation plan shall propose a fair, transparent and non-discriminatory competitive procurement process consistent with §54.186 for the acquisition of sufficient electric generation supply, at prevailing market prices, to meet the demand of all of the default service provider’s retail electric customers for the term of service. The default service plan shall identify its method of compliance with the Alternative Energy Portfolio Standards Act (73 P.S. §§ 1647.1—1647.7). A DEFAULT SERVICE PROGRAM SHALL INCLUDE THE FOLLOWING ELEMENTS:

(1) A PROCUREMENT PLAN IDENTIFYING THE DSP’S ELECTRIC GENERATION SUPPLY ACQUISITION STRATEGY FOR THE
PERIOD OF SERVICE. THE PROCUREMENT PLAN SHOULD IDENTIFY THE MEANS OF SATISFYING THE MINIMUM PORTFOLIO REQUIREMENTS OF THE ALTERNATIVE ENERGY PORTFOLIO STANDARDS ACT, 73 P.S. § 1648.1, ET SEQ., FOR THE PERIOD OF SERVICE.

(2) AN IMPLEMENTATION PLAN IDENTIFYING THE SCHEDULES AND TECHNICAL REQUIREMENTS OF COMPETITIVE BID SOLICITATIONS AND SPOT MARKET ENERGY PURCHASES, CONSISTENT WITH § 54.186.

(3) A RATE DESIGN PLAN RECOVERING ALL REASONABLE COSTS OF DEFAULT SERVICE, INCLUDING A SCHEDULE OF RATES, RULES AND CONDITIONS OF DEFAULT SERVICE IN THE FORM OF PROPOSED REVISIONS TO ITS TARIFF.

(4) DOCUMENTATION THAT THE PROGRAM IS CONSISTENT WITH THE LEGAL AND TECHNICAL REQUIREMENTS PERTAINING TO THE GENERATION, SALE AND TRANSMISSION OF ELECTRICITY OF THE RTO OR OTHER ENTITY IN WHOSE CONTROL AREA THE DSP IS PROVIDING SERVICE. THE DEFAULT SERVICE PROCUREMENT PLAN’S PERIOD OF SERVICE SHALL ALIGN WITH THE PLANNING PERIOD OF THAT RTO OR OTHER ENTITY.

(5) CONTINGENCY PLANS TO ENSURE THE RELIABLE PROVISION OF DEFAULT SERVICE WHEN A WHOLESALE GENERATION SUPPLIER FAILS TO MEET ITS CONTRACTUAL OBLIGATIONS.

(6) COPIES OF AGREEMENTS OR FORMS TO BE USED IN THE PROCUREMENT OF ELECTRIC GENERATION SUPPLY FOR DEFAULT SERVICE CUSTOMERS. THIS SHALL INCLUDE ALL DOCUMENTS USED AS PART OF THE IMPLEMENTATION PLAN, INCLUDING SUPPLIER MASTER AGREEMENTS, REQUEST FOR PROPOSAL DOCUMENTS,
CREDIT DOCUMENTS, AND CONFIDENTIALITY AGREEMENTS. WHEN APPLICABLE, THE DEFAULT SERVICE PROVIDER SHALL USE STANDARDIZED FORMS AND AGREEMENTS THAT HAVE BEEN APPROVED BY THE COMMISSION.

(7) A SCHEDULE IDENTIFYING GENERATION CONTRACTS OF GREATER THAN 2 YEARS IN EFFECT BETWEEN A DSP, WHEN IT IS THE INCUMBENT EDC, AND RETAIL CUSTOMERS IN THAT SERVICE TERRITORY. THE SCHEDULE SHOULD IDENTIFY THE LOAD SIZE AND END DATE OF THE CONTRACTS. THE SCHEDULE SHALL ONLY BE PROVIDED TO THE COMMISSION AND WILL BE TREATED AS CONFIDENTIAL.

(e) The Commission may, FOLLOWING NOTICE AND OPPORTUNITY TO BE HEARD, direct that some or all default service providers DSPS file joint default service implementation plans PROGRAMS that propose a competitive procurement process to procure TO ACQUIRE electric generation supply for all of their default service customers. In the absence of such a directive, some or all default service providers DSPS may jointly file default service plans PROGRAMS that propose a competitive procurement process to procure OR COORDINATE THE SCHEDULING OF COMPETITIVE BID SOLICITATIONS TO ACQUIRE electric generation for all of their default service customers. A multi-service territory competitive procurement process PROCUREMENT AND IMPLEMENTATION PLAN must comply with § 54.186.

(f) A default service provider shall document that its proposal is consistent with the legal and technical requirements pertaining to the generation, sale and transmission of electricity of the RTO or ISO in whose control area it is providing service. The default service plan’s term of service and generation supply acquisition processes shall align with the planning period of that RTO or ISO.

(g) The default service implementation plan must include a schedule of rates, rules and conditions of default service in the form of proposed revisions to its tariff.
default service provider may use the already effective retail customer classes in the
EDC’s service territory, or may propose a reclassification of retail customers.

(h) The default service implementation plan must identify the costs, consistent
with §54.187, that will be recovered through a schedule of rates for the provision of
default service.

(i) The default service implementation plan must include reasonable credit
requirements, or other reasonable assurances of any supplier of electric generation
services’ ability to perform, as approved by the Commission.

(j) The default service implementation plan must identify the load size and end
date of all existing long-term generation contracts that are in effect between the EDC and
a retail customer within its service territory.

(k) The default service implementation plan should include copies of any
proposed confidentiality agreements for the protection of proprietary information of the
default service provider and generation suppliers. The Commission will approve
reasonable confidentiality agreements, including expiration provisions, that will be
binding on the default service provider, generation suppliers and any third party involved
in the administration, review or monitoring of a default service supply procurement
process.

(l) The default service provider shall include in its implementation plan a
replacement procurement process to ensure the reliable provision of default service in the
event a supplier fails to deliver electric generation supply it has agreed to provide
pursuant to the terms of a Commission-approved competitive procurement process.

(m) The Commission may issue orders further specifying the form and content
of default service implementation plans when necessary to enforce or carry out the
provisions of 66 Pa. C.S. §§2801–2812 (relating to Electricity Generation Customer
Choice and Competition Act), and other applicable law.

(F) DSPS SHALL INCLUDE REQUESTS FOR WAIVERS FROM THE
PROVISIONS OF THIS SUBCHAPTER IN THEIR DEFAULT SERVICE PROGRAM
FILINGS. FOR DSPS WITH LESS THAN 50,000 RETAIL CUSTOMERS, THE

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COMMISSION WILL GRANT WAIVERS TO THE EXTENT NECESSARY TO REDUCE THE REGULATORY, FINANCIAL OR TECHNICAL BURDEN ON THE DSP OR TO THE EXTENT OTHERWISE IN THE PUBLIC INTEREST.

§ 54.186. Default service supply procurement AND IMPLEMENTATION PLANS.

(a) A default service provider shall procure the electricity needed to provide default service only through a competitive procurement process or replacement procurement process approved by the Commission, with the following exceptions:

1. Hourly priced service provided pursuant to § 54.187(e).
2. Supply procured through RTO or ISO administered energy markets consistent with subsection (g), 54.187(i) or 54.188(e) (relating to Commission review of default service implementation plans).

A DSP SHALL ACQUIRE ELECTRIC GENERATION SUPPLY AT PREVAILING MARKET PRICES FOR DEFAULT SERVICE CUSTOMERS IN A MANNER CONSISTENT WITH PROCUREMENT AND IMPLEMENTATION PLANS APPROVED BY THE COMMISSION.

(b) A default service provider’s competitive procurement process PROCUREMENT PLAN shall adhere to the following standards:

1. A default service provider’s supplier affiliate may participate in any competitive procurement process. The default service provider shall propose and implement protocols to ensure that its supplier affiliate does not receive an advantage in either the solicitation and evaluation of competitive bids, or any other aspect of the competitive procurement process. The process shall comply with the codes of conduct promulgated by the Commission at § 54.122 (relating to code of conduct).

2. A default service provider’s proposed competitive procurement process shall include:

   (i) A bidding schedule.
(ii) A definition and description of the power supply products on which potential suppliers shall bid.

(iii) Bid price formats.

(iv) The time period during which the power will need to be supplied for each power supply product.

(v) Bid submission instructions and format.

(vi) Bid evaluation criteria.

(vii) Relevant load data, including the following:

(A) Aggregated customer hourly usage data for all retail customers.

(B) Number of retail customers.

(C) Capacity peak load contribution figures by rate schedule.

(D) Historical monthly retention figures by rate schedule.

(E) Estimated loss factors by rate schedule.

(F) Customer size distribution by rate schedule.

1) THE PROCUREMENT PLAN MUST BE DESIGNED TO ACQUIRE ELECTRIC GENERATION SUPPLY AT PREVAILING MARKET PRICES TO MEET THE DSP’S ANTICIPATED DEFAULT SERVICE OBLIGATION AT REASONABLE COSTS.

2) DSPS WITH LOADS OF 50 MW OR LESS SHALL EVALUATE THE COST AND BENEFITS OF JOINING WITH OTHER DSPS OR AFFILIATES IN CONTRACTING FOR ELECTRIC SUPPLY.

3) PROCUREMENT PLANS MAY INCLUDE SOLICITATIONS AND CONTRACTS WHOSE DURATION EXTENDS BEYOND THE PROGRAM PERIOD.

4) ELECTRIC GENERATION SUPPLY SHALL BE ACQUIRED BY COMPETITIVE BID SOLICITATION PROCESSES, SPOT MARKET ENERGY PURCHASES, OR A COMBINATION OF BOTH.
THE DSP’S SUPPLIER AFFILIATE MAY PARTICIPATE IN A COMPETITIVE BID SOLICITATION PROCESS USED AS PART OF THE PROCUREMENT PLAN SUBJECT TO THE FOLLOWING CONDITIONS:

(I) THE DSP SHALL PROPOSE AND IMPLEMENT PROTOCOLS TO ENSURE THAT ITS SUPPLIER AFFILIATE DOES NOT RECEIVE AN ADVANTAGE IN THE SOLICITATION AND EVALUATION OF COMPETITIVE BIDS, OR OTHER ASPECT OF THE IMPLEMENTATION PLAN.

(II) THE COMPETITIVE BID SOLICITATION PROCESS SHALL COMPLY WITH THE CODES OF CONDUCT PROMULGATED BY THE COMMISSION AT § 54.122 (RELATING TO CODE OF CONDUCT).

(c) A default service provider may employ a third-party to design and implement the competitive procurement process. A DSP’S IMPLEMENTATION PLAN SHALL ADHERE TO THE FOLLOWING STANDARDS:

(1) A COMPETITIVE BID SOLICITATION PROCESS USED AS PART OF THE DEFAULT SERVICE IMPLEMENTATION PLAN SHALL PROVIDE, TO THE EXTENT APPLICABLE AND AT THE APPROPRIATE TIME, THE FOLLOWING INFORMATION TO SUPPLIERS:

(I) A BIDDING SCHEDULE.

(II) A DEFINITION AND DESCRIPTION OF THE POWER SUPPLY PRODUCTS ON WHICH POTENTIAL SUPPLIERS SHALL BID.

(III) BID PRICE FORMATS.

(IV) A TIME PERIOD DURING WHICH THE POWER WILL NEED TO BE SUPPLIED FOR EACH POWER SUPPLY PRODUCT.

(V) BID SUBMISSION INSTRUCTIONS AND FORMAT.

(VI) PRICE-DETERMINATIVE BID EVALUATION CRITERIA.
(VII) CURRENT LOAD DATA FOR RATE SCHEDULES OR MAXIMUM REGISTERED PEAK LOAD GROUPINGS, INCLUDING THE FOLLOWING:
(A) HOURLY USAGE DATA.
(B) NUMBER OF RETAIL CUSTOMERS.
(C) CAPACITY PEAK LOAD CONTRIBUTION FIGURES.
(D) HISTORICAL MONTHLY RETENTION FIGURES.
(E) ESTIMATED LOSS FACTORS.
(F) CUSTOMER SIZE DISTRIBUTION.

(2) THE DEFAULT SERVICE IMPLEMENTATION PLAN SHALL INCLUDE FAIR AND NON-DISCRIMINATORY BIDDER QUALIFICATION REQUIREMENTS, INCLUDING FINANCIAL AND OPERATIONAL QUALIFICATIONS, OR OTHER REASONABLE ASSURANCES OF A SUPPLIER OF ELECTRIC GENERATION SERVICES’ ABILITY TO PERFORM.

(3) A COMPETITIVE BID SOLICITATION PROCESS USED AS PART OF THE IMPLEMENTATION PLAN SHALL BE SUBJECT TO MONITORING BY THE COMMISSION OR AN INDEPENDENT THIRD PARTY EVALUATOR SELECTED BY THE DSP IN CONSULTATION WITH THE COMMISSION. A THIRD PARTY EVALUATOR SHALL OPERATE AT THE DIRECTION OF THE COMMISSION. COMMISSION STAFF AND A THIRD PARTY EVALUATOR INVOLVED IN MONITORING THE PROCUREMENT PROCESS SHALL HAVE FULL ACCESS TO ALL INFORMATION PERTAINING TO THE COMPETITIVE PROCUREMENT PROCESS, EITHER REMOTELY OR WHERE THE PROCESS IS ADMINISTERED. A THIRD PARTY EVALUATOR RETAINED FOR PURPOSES OF MONITORING THE COMPETITIVE PROCUREMENT PROCESS SHALL BE SUBJECT TO CONFIDENTIALITY AGREEMENTS IDENTIFIED IN § 54.185(D)(6).
(4) THE DSP OR THIRD PARTY EVALUATOR SHALL REVIEW AND SELECT WINNING BIDS PROCURED THROUGH A COMPETITIVE BID SOLICITATION PROCESS IN A NON-DISCRIMINATORY MANNER BASED ON THE PRICE DETERMINATIVE BID EVALUATION CRITERIA SET FORTH CONSISTENT WITH SUBSECTION (C)(1)(VI).

(5) THE BIDS SUBMITTED BY A SUPPLIER IN RESPONSE TO A COMPETITIVE BID SOLICITATION PROCESS SHALL BE TREATED AS CONFIDENTIAL PURSUANT TO THE CONFIDENTIALITY AGREEMENT APPROVED BY THE COMMISSION PURSUANT TO § 54.185(D)(6). THE DSP, THE COMMISSION, AND A THIRD PARTY INVOLVED IN THE ADMINISTRATION, REVIEW OR MONITORING OF THE BID SOLICITATION PROCESS SHALL BE SUBJECT TO THIS CONFIDENTIALITY PROVISION.

(d) The competitive procurement process may be subject to direct oversight by the Commission or an independent third party. Any third party shall report to the Commission. Commission staff and any third party involved in oversight of the procurement process shall have full access to all information pertaining to the competitive procurement process, and may monitor the process either remotely or where the process is administered. Any third party retained for purposes of monitoring the competitive procurement process shall be subject to confidentiality agreements identified in §54.185(k). THE DSP MAY PETITION FOR MODIFICATIONS TO THE APPROVED PROCUREMENT AND IMPLEMENTATION PLANS WHEN MATERIAL CHANGES IN WHOLESALE ENERGY MARKETS OCCUR TO ENSURE THE ACQUISITION OF SUFFICIENT SUPPLY AT PREVAILING MARKET PRICES. THE DSP SHALL MONITOR CHANGES IN WHOLESALE ENERGY MARKETS TO ENSURE THAT ITS PROCUREMENT PLAN CONTINUES TO REFLECT THE INCURRENCE OF REASONABLE COSTS, CONSISTENT WITH 66 PA.C.S. § 2807(E)(3) (RELATING TO THE DUTIES OF ELECTRIC DISTRIBUTION COMPANIES).
(e) The default service provider shall evaluate and select winning bids in a non-discriminatory manner based on bid evaluation criteria set forth consistent with subsection (b)(2)(vi).

(f) The Commission will review the acquisition of generation supply and verify compliance with the approved competitive procurement process as follows:

1. The Commission’s review will occur within a time period as specified in the approved competitive procurement process.
2. The review period may not be less than 3 business days.
3. The Commission’s verification of compliance with an approved competitive procurement process will constitute its certification of the default service provider’s compliance with the approved default service implementation plan.

(g) If the implementation of a competitive procurement process under this section does not result in sufficient electric supply to meet the default service provider’s full load requirements, the default service provider shall repeat the competitive procurement process. The default service provider may petition for necessary changes to the previously approved competitive procurement process to ensure the acquisition of sufficient supply. When necessary to procure electric generation supply before the completion of another competitive procurement process, a default service provider shall acquire supply at prevailing market prices and shall fully recover reasonable costs associated with this activity. In this circumstance, the prevailing market price shall be the price of electricity in the RTO or ISO’s administered energy markets in whose control area that service is being provided. The default service provider shall follow acquisition strategies that reflect the incurrence of reasonable costs, consistent with 66 Pa.C.S. §2807(e)(3) (relating to the duties of electric distribution companies), when selecting from the various options available in these energy markets.

(h) The bids submitted by a supplier under the competitive procurement process shall be treated as confidential through the expiration date identified in the confidentiality agreement approved by Commission pursuant to §54.185(k). The default
service provider, the Commission, and any third party involved in the administration, review or monitoring of the procurement process, shall be subject to this confidentiality provision.

§ 54.187. Default service rates RATE DESIGN and the recovery of reasonable costs.

(a) The costs incurred for providing default service shall be recovered through the following mechanisms or charges:

(1) The generation supply charge is a nonreconcilable charge that includes all reasonable costs associated with the acquisition of generation supply, exclusive of the costs of generation supply recovered through paragraph (3), to meet default service demand. The associated costs with this charge include:

(i) The prevailing market price of energy;

(ii) The prevailing market price of RTO or ISO capacity or any similar obligation;

(iii) FERC-approved ancillary services and transmission charges;

(iv) Required RTO or ISO charges;

(v) Applicable taxes;

(vi) Other reasonable, identifiable generation supply acquisition costs.

(2) The customer charge is a nonreconcilable, fixed charge, set on a per customer class basis, that includes all identifiable, reasonable costs associated with providing default service to an average member of that class, exclusive of generation supply costs and costs recovered through paragraph (3). The associated costs with this charge include:

(i) Default service related costs for customer billing, collections, customer service, meter reading, and uncollectible debt;

(ii) A reasonable return or risk component for the default service provider.
(iii) Applicable taxes.
(iv) Other reasonable and identifiable administrative or regulatory expenses.

(3) A default service provider shall use an automatic energy adjustment clause, consistent with 66 Pa.C.S. § 1307 (relating to sliding scale of rates; adjustments) to recover reasonable costs incurred through compliance with the Alternative Energy Portfolio Standards Act (73 P.S. §§ 1648.1–1648.7).

(4) The costs recovered through the preceding charges and mechanisms may not be recovered by an EDC acting as a default service provider through its Commission-approved distribution rates. THE COSTS INCURRED FOR PROVIDING DEFAULT SERVICE SHALL BE RECOVERED THROUGH A DEFAULT SERVICE RATE SCHEDULE. THE RATE SCHEDULE SHALL BE DESIGNED TO RECOVER FULLY ALL REASONABLE COSTS INCURRED BY THE DSP DURING THE PERIOD DEFAULT SERVICE IS PROVIDED TO CUSTOMERS, BASED ON THE AVERAGE COST TO ACQUIRE SUPPLY FOR EACH CUSTOMER CLASS.

(b) A default service plan must include a fixed rate option for all residential customers. EXCEPT FOR RATES AVAILABLE CONSISTENT WITH 54.187(F), A DEFAULT SERVICE CUSTOMER SHALL BE OFFERED A SINGLE RATE OPTION, WHICH SHALL BE IDENTIFIED AS THE PTC AND DISPLAYED AS A SEPARATE LINE ITEM ON A CUSTOMER’S MONTHLY BILL.

(c) A default service implementation plan must include a fixed rate option for nonresidential default service customers whose load test indicates a registered peak demand of 500 or less kilowatts. THE RATES CHARGED FOR DEFAULT SERVICE MAY NOT DECLINE WITH THE INCREASE IN KILOWATT HOURS OF ELECTRICITY USED BY A DEFAULT SERVICE CUSTOMER IN A BILLING PERIOD.

(d) The default service provider shall include an hourly rate in its implementation plan for all default service customers whose load test indicates a
registered peak demand of greater than 500 kilowatts. The default service provider may propose a fixed rate for these customers in its default service implementation plan. THE PTC SHALL BE DESIGNED TO RECOVER ALL DEFAULT SERVICE COSTS, INCLUDING GENERATION, TRANSMISSION, AND OTHER DEFAULT SERVICE COST ELEMENTS, INCURRED IN SERVING THE AVERAGE MEMBER OF A CUSTOMER CLASS. AN EDC’S DEFAULT SERVICE COSTS MAY NOT BE RECOVERED THROUGH THE DISTRIBUTION RATE. COSTS CURRENTLY RECOVERED THROUGH THE DISTRIBUTION RATE, WHICH ARE REALLOCATED TO THE DEFAULT SERVICE RATE, MAY NOT BE RECOVERED THROUGH THE DISTRIBUTION RATE. THE DISTRIBUTION RATE MUST BE REDUCED TO REFLECT COSTS REALLOCATED TO THE DEFAULT SERVICE RATE.

(c) The rate for hourly priced service shall include:

(1) The RTO’s or ISO’s LMP or the equivalent pricing mechanism.
(2) The prevailing market price of RTO or ISO capacity or any similar obligation.
(3) FERC-approved ancillary services and transmission charges.
(4) Required RTO or ISO charges.
(5) Applicable taxes.
(6) Other FERC-approved or reasonable, identifiable RTO or ISO charges and costs directly related to the hourly priced service.
(7) Other reasonable and identifiable administrative or regulatory expenses.

A DSP SHALL USE AN AUTOMATIC ENERGY ADJUSTMENT CLAUSE, CONSISTENT WITH 66 PA.C.S. § 1307 (PERTAINING TO SLIDING SCALES OF RATES; ADJUSTMENTS) AND 52 PA. CODE § 75.1, ET SEQ. (PERTAINING TO ALTERNATIVE ENERGY PORTFOLIO STANDARDS), TO RECOVER ALL REASONABLE COSTS INCURRED THROUGH COMPLIANCE WITH THE ALTERNATIVE ENERGY PORTFOLIO
STANDARDS ACT, 73 P.S. §1648.1, ET SEQ. THE USE OF AN AUTOMATIC
ADJUSTMENT CLAUSE SHALL BE SUBJECT TO AUDIT AND ANNUAL
REVIEW, CONSISTENT WITH 66 PA.C.S. §§ 1307(D) AND (E)
(PERTAINING TO FUEL COST ADJUSTMENT AUDITS; AUTOMATIC
ADJUSTMENT REPORTS AND PROCEEDINGS).

(f) The default service implementation plan must include rates that correspond
to demand side response and demand side management programs available to retail
customers in that EDC service territory. A DSP MAY USE AN AUTOMATIC ENERGY
ADJUSTMENT CLAUSE TO RECOVER REASONABLE NON-ALTERNATIVE
ENERGY DEFAULT SERVICE COSTS. THE USE OF AN AUTOMATIC
ADJUSTMENT CLAUSE SHALL BE SUBJECT TO AUDIT AND ANNUAL
REVIEW, CONSISTENT WITH 66 PA.C.S. §§ 1307(D) AND (E) (PERTAINING TO
FUEL COST ADJUSTMENT AUDITS; AUTOMATIC ADJUSTMENT REPORTS
AND PROCEEDINGS). A DSP MAY COLLECT INTEREST FROM RETAIL
CUSTOMERS ON THE RECOVERIES OF UNDER COLLECTION OF DEFAULT
SERVICE COSTS AT THE LEGAL RATE OF INTEREST. REFUNDS TO
CUSTOMERS FOR OVER RECOVERIES SHALL BE MADE WITH INTEREST, AT
THE LEGAL RATE OF INTEREST PLUS TWO PERCENT.

(g) The default service implementation plan may include mechanisms that
allow default service providers to adjust their prices during the term of service to recover
reasonable, incremental costs of significant changes in the number of default service
customers or reasonable, incremental costs of other events that would materially
prejudice the reliable provision of default service and the full recovery of reasonable
costs. THE DEFAULT SERVICE RATE SCHEDULE SHALL INCLUDE RATES
THAT CORRESPOND TO DEMAND SIDE RESPONSE AND DEMAND SIDE
MANAGEMENT PROGRAMS, AS DEFINED AT 73 P.S. § 1648.2 (PERTAINING TO
DEFINITIONS), WHEN THE COMMISSION MANDATES THESE RATES
PURSUANT TO ITS AUTHORITY UNDER 66 PA.C.S. § 101, ET SEQ.
(h) The default service provider’s projected and actual incurred costs for providing service may not be subject to Commission review and reconciliation except in extraordinary circumstances, or as provided in subsection (a)(3). DEFAULT SERVICE RATES SHALL BE ADJUSTED ON A QUARTERLY BASIS, OR MORE FREQUENTLY, FOR ALL CUSTOMER CLASSES WITH A MAXIMUM REGISTERED PEAK LOAD UP TO 25 KW, IN ORDER TO ENSURE THE RECOVERY OF COSTS REASONABLY INCURRED IN ACQUIRING ELECTRICITY AT PREVAILING MARKET PRICES AND TO REFLECT THE SEASONAL COST OF ELECTRICITY. DSPS MAY PROPOSE ALTERNATIVE DIVISIONS OF CUSTOMERS BY MAXIMUM REGISTERED PEAK LOAD TO PRESERVE EXISTING CUSTOMER CLASSES.

(i) When a generation supplier fails to deliver generation supply to a default service provider, the default service provider shall be responsible for acquiring replacement generation supply consistent with its Commission-approved replacement procurement process. When necessary to procure electric generation supply before the completion of the replacement procurement process, a default service provider shall acquire supply at prevailing market prices and shall fully recover all reasonable costs associated with this activity. In this circumstance, the prevailing market price will be the price of electricity in the RTO or ISO’s administered energy markets in whose control area the default service is being provided. The default service provider shall follow acquisition strategies that reflect the incurrence of reasonable costs, consistent with 66 Pa. C.S. §2807(e)(3) (relating to duties of electric distribution companies), when selecting from the various options available in these energy markets. DEFAULT SERVICE RATES SHALL BE ADJUSTED ON A QUARTERLY BASIS, OR MORE FREQUENTLY, FOR ALL CUSTOMER CLASSES WITH A MAXIMUM REGISTERED PEAK LOAD OF 25 KW TO 500 KW, IN ORDER TO ENSURE THE RECOVERY OF COSTS REASONABLY INCURRED IN ACQUIRING ELECTRICITY AT PREVAILING MARKET PRICES AND TO REFLECT THE SEASONAL COST OF ELECTRICITY. DSPS MAY PROPOSE ALTERNATIVE
DIVISIONS OF CUSTOMERS BY MAXIMUM REGISTERED PEAK LOAD TO PRESERVE EXISTING CUSTOMER CLASSES.

(J) DEFAULT SERVICE RATES SHALL BE ADJUSTED ON A MONTHLY BASIS, OR MORE FREQUENTLY, FOR ALL CUSTOMER CLASSES WITH A REGISTERED PEAK LOAD OF EQUAL TO OR GREATER THAN 500 KW IN ORDER TO ENSURE THE RECOVERY OF COSTS REASONABLY INCURRED IN ACQUIRING ELECTRICITY AT PREVAILING MARKET PRICES AND TO REFLECT THE SEASONAL COST OF ELECTRICITY. DSPS MAY PROPOSE ALTERNATIVE DIVISIONS OF CUSTOMERS BY REGISTERED PEAK LOAD TO PRESERVE EXISTING CUSTOMER CLASSES.

(K) WHEN A SUPPLIER FAILS TO DELIVER ELECTRIC GENERATION SUPPLY TO A DSP, THE DSP SHALL BE RESPONSIBLE FOR ACQUIRING REPLACEMENT ELECTRIC GENERATION SUPPLY CONSISTENT WITH ITS COMMISSION APPROVED CONTINGENCY PLAN. WHEN NECESSARY TO PROCURE ELECTRIC GENERATION SUPPLY BEFORE THE IMPLEMENTATION OF A CONTINGENCY PLAN, A DSP SHALL ACQUIRE SUPPLY AT PREVAILING MARKET PRICES AND SHALL FULLY RECOVER ALL REASONABLE COSTS ASSOCIATED WITH THIS ACTIVITY THAT ARE NOT OTHERWISE RECOVERED THROUGH ITS CONTRACT TERMS WITH THE DEFAULT SUPPLIER. THE DSP SHALL FOLLOW ACQUISITION STRATEGIES THAT REFLECT THE INCURRENCE OF REASONABLE COSTS, CONSISTENT WITH 66 PA.C.S. § 2807(E)(3) (RELATING TO DUTIES OF ELECTRIC DISTRIBUTION COMPANIES), WHEN SELECTING FROM THE VARIOUS OPTIONS AVAILABLE IN THESE ENERGY MARKETS.
§ 54.188. Commission review of default service implementation plans PROGRAMS AND RATES.

(a) A default service implementation plan PROGRAM shall WILL initially be referred to the Office of Administrative Law Judge for further proceedings as may be required.

(b) The Commission will issue an order within 6 7 months of a plan’s PROGRAM’S filing with the Commission on whether the default service implementation plan PROGRAM demonstrates compliance with this subchapter and the provisions of 66 Pa.C.S. §§ 2801-2812 (relating to the Electricity Generation Customer Choice and Competition Act). The Commission may order modification of the terms of the proposed plan to ensure that a default service plan is compliant.

(c) The Commission will evaluate the default service implementation plan to ensure that it includes a fair, transparent and non-discriminatory competitive procurement process for all potential suppliers provided under §54.186 (relating to default service supply procurement). UPON ENTRY OF THE COMMISSION’S FINAL ORDER, A DSP SHALL ACQUIRE GENERATION SUPPLY FOR THE PERIOD OF SERVICE IN A MANNER CONSISTENT WITH THE TERMS OF THE APPROVED PROCUREMENT AND IMPLEMENTATION PLANS AND CONSISTENT WITH THE STANDARDS IDENTIFIED AT § 54.186 (RELATING TO DEFAULT SERVICE PROCUREMENT AND IMPLEMENTATION PLANS).

(d) Upon entry of the Commission’s final order, the default service provider shall acquire generation supply for the term of service in a manner consistent with the terms of the approved competitive procurement process provided under $54.186, and report the bids submitted by EGSs in writing to the Commission. UPON RECEIVING WRITTEN NOTICE, THE COMMISSION WILL HAVE 1 BUSINESS DAY, TO APPROVE OR DISAPPROVE THE RESULTS OF A COMPETITIVE BID SOLICITATION PROCESS USED BY A DSP AS PART OF ITS PROCUREMENT PLAN. WHEN THE COMMISSION DOES NOT ACT WITHIN 1 BUSINESS DAY THE RESULTS OF THE PROCESS WILL BE DEEMED APPROVED. THE

(c) The Commission will certify the results of a competitive procurement process in their entirety or reject them due to noncompliance with the approved procurement process. If the Commission rejects the results due to noncompliance, the default service provider shall repeat the approved competitive procurement process. When necessary to procure electric generation supply before the completion of the subsequent competitive procurement process, a default service provider shall acquire supply at prevailing market prices and shall fully recover all reasonable costs associated with this activity. In this circumstance, the prevailing market price will be the price of electricity in the RTO or ISO’s administered energy markets in whose control area that service is being provided. The default service provider shall follow acquisition strategies that reflect the incurrence of reasonable costs, consistent with 66 Pa. C.S. §2807(e)(3) (relating to duties of electric distribution companies), when selecting from the various options available in these energy markets. A DSP SHALL ADHERE TO THE
FOLLOWING PROCEDURES IN OBTAINING APPROVAL OF DEFAULT SERVICE RATES AND PROVIDING NOTICE TO DEFAULT SERVICE CUSTOMERS:

(1) A DSP SHALL PROVIDE ALL CUSTOMERS NOTICE OF THE FILING OF A DEFAULT SERVICE PROGRAM IN A SIMILAR MANNER AS FOUND AT 52 PA. CODE § 53.68 (RELATING TO NOTICE REQUIREMENTS).

(2) A DSP SHALL PROVIDE ALL CUSTOMERS NOTICE OF THE INITIAL DEFAULT SERVICE RATES AND TERMS AND CONDITIONS OF SERVICE 60 DAYS BEFORE THEIR EFFECTIVE DATE, OR 30 DAYS AFTER BIDDING HAS CONCLUDED, WHICHEVER IS SOONER, UNLESS ANOTHER TIME PERIOD IS APPROVED BY THE COMMISSION. THE DSP SHALL PROVIDE WRITTEN NOTICE TO THE NAMED PARTIES IDENTIFIED IN § 54.185(B) (PERTAINING TO DEFAULT SERVICE PROGRAMS) CONTAINING AN EXPLANATION OF THE METHODOLOGY USED TO CALCULATE THE PRICE FOR ELECTRIC SERVICE.

(3) AFTER THE INITIAL STEPS OF A DEFAULT SERVICE PROCUREMENT AND IMPLEMENTATION PLAN ARE COMPLETED, THE DSP SHALL FILE WITH THE COMMISSION TARIFF SUPPLEMENTS DESIGNED TO REFLECT, FOR EACH CUSTOMER CLASS, THE RATES TO BE CHARGED FOR DEFAULT SERVICE. THE TARIFF SUPPLEMENTS SHALL BE ACCOMPANIED BY SUPPORTING DOCUMENTATION ADEQUATE TO DEMONSTRATE ADHERENCE TO THE PROCUREMENT PLAN APPROVED BY THE COMMISSION, THE PROCUREMENT PLAN RESULTS AND THE TRANSLATION OF THOSE RESULTS INTO CUSTOMER RATES.

(4) A CUSTOMER OR PARTY IDENTIFIED IN § 54.185(B) MAY FILE EXCEPTIONS TO THE INITIAL DEFAULT SERVICE TARIFFS WITHIN 20 DAYS OF THE DATE THE TARIFFS ARE FILED WITH THE
COMMISSION. THE EXCEPTIONS SHALL BE LIMITED TO WHETHER THE DSP PROPERLY IMPLEMENTED THE PROCUREMENT PLAN APPROVED BY THE COMMISSION AND ACCURATELY CALCULATED THE RATES. THE COMMISSION WILL RESOLVE FILED EXCEPTIONS BY ORDER. THE COMMISSION MAY ALLOW THE DEFAULT RATES TO BECOME EFFECTIVE PENDING THE RESOLUTION OF THOSE EXCEPTIONS.

(f) Upon completion of the competitive procurement process, the default service provider shall provide written notice to default service customers and the named parties identified in §54.185(b) (relating to default service implementation plans and terms of service) of the Commission-certified default service prices and terms and conditions of service no later than 60 days before their effective date, unless another time period is approved by the Commission. The default service provider shall also provide written notice to the named parties identified in §54.185(b) containing an explanation of the methodology used to calculate the price for electric service. A DSP SHALL SUBMIT TARIFF SUPPLEMENTS ON A QUARTERLY OR MORE FREQUENT BASIS, CONSISTENT WITH § 54.187 (H) AND (I) (PERTAINING TO DEFAULT SERVICE RATE DESIGN AND RECOVERY OF REASONABLE COSTS), TO REVISE DEFAULT SERVICE RATES TO ENSURE THE RECOVERY OF COSTS REASONABLY INCURRED IN ACQUIRING ELECTRICITY AT PREVAILING MARKET PRICES. THE DSP SHALL PROVIDE WRITTEN NOTICE TO THE NAMED PARTIES IDENTIFIED IN § 54.185(B) OF THE PROPOSED RATES AT THE TIME OF THE TARIFF FILINGS. THE TARIFF SUPPLEMENTS SHALL BE POSTED TO THE DSP’S PUBLIC INTERNET DOMAIN AT THE TIME THEY ARE FILED WITH THE COMMISSION. A CUSTOMER OR THE PARTIES IDENTIFIED IN § 54.185(B) MAY FILE EXCEPTIONS TO THE DEFAULT SERVICE TARIFFS WITHIN 20 DAYS OF THE DATE THE TARIFFS ARE FILED WITH THE COMMISSION. THE EXCEPTIONS SHALL BE LIMITED TO WHETHER THE DSP HAS PROPERLY IMPLEMENTED THE PROCUREMENT PLAN APPROVED BY
THE COMMISSION AND ACCURATELY CALCULATED THE RATES. THE DSP SHALL POST THE REVISED PTC FOR EACH CUSTOMER CLASS WITHIN 1 BUSINESS DAY OF ITS EFFECTIVE DATE TO ITS PUBLIC INTERNET DOMAIN TO ENABLE CUSTOMERS TO MAKE AN INFORMED DECISION ABOUT ELECTRIC GENERATION SUPPLY OPTIONS.

(g) A default service provider may petition for a waiver of any part of this subchapter, in a manner consistent with §5.43 (relating to petitions for issuance, amendment or waiver of regulations). The Commission may grant waivers of these subchapter to ensure the reliable provision of default service and to enforce and carry out the provisions of 66 Pa. C.S. §§2801-2812 and other applicable laws.

§ 54.189. Default service customers.

(a) At the conclusion of an EDC’s Commission approved generation rate cap, retail customers who are not receiving generation service from an EGS shall be assigned to the Commission-approved default service implementation plan DSP IN THAT SERVICE TERRITORY.

(b) A default service provider DSP shall accept applications for default service from new retail customers WHEN THE CUSTOMERS COMPLY WITH COMMISSION REGULATIONS PERTAINING TO APPLICATIONS FOR SERVICE, INCLUDING THOSE AT § 56.1, *ET SEQ.* (PERTAINING TO STANDARDS AND BILLING PRACTICES FOR RESIDENTIAL CUSTOMERS) and retail customers who switch from an EGS, if the customers comply with all Commission regulations pertaining to applications for service SHALL ACCEPT ALL RETAIL CUSTOMERS ASSIGNED TO ITS DEFAULT SERVICE WHO SWITCH FROM AN EGS.

(c) A default service provider DSP shall treat a customer who leaves an EGS and applies for default service as it would a new applicant for default service.

(d) A default service customer may choose to receive its generation service from an EGS at any time, if the customer complies with all Commission regulations
pertaining to changing generation service providers AT § 57.1, ET SEQ. (PERTAINING TO ELECTRIC SERVICE)

(e) A default service provider DSP may not charge a fee to a retail customer that changes FOR CHANGING its generation service provider in a manner consistent with Commission regulations.
CHAPTER 57. ELECTRIC SERVICE

Subchapter M: STANDARDS FOR CHANGING A CUSTOMER’S ELECTRICITY GENERATION SUPPLIER

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§ 57.178. [Provider of Last Resort] Default service provider.

This subchapter does not apply when the customer's service is discontinued by the EGS and subsequently provided by the [provider of last resort] default service provider because no other EGS is willing to provide service to the customer.

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Appendix 2 – Policy Statement
FINAL POLICY STATEMENT

BY THE COMMISSION:

On February, 8, 2007, the Commission issued a proposed version of this policy statement and solicited public comments. The Commission has completed its review of the comments and today issues this final policy statement. This policy statement is being issued in conjunction with final form regulations on default service and a final order identifying price mitigation strategies.\(^{41}\)

In December of 2004 the Commission issued a proposed rulemaking order to define the obligation of electric distribution companies (“EDC”) to serve retail electric customers at the conclusion of the restructuring transition periods. Rulemaking Re Electric Distribution Companies’ Obligation to Serve Retail Customers at the Conclusion of the Transition Period Pursuant To 66 Pa.C.S. § 2807(e)(2), Docket No. L-00040169

\(^{41}\) Policies to Mitigate Potential Electricity Price Increases, Docket No. M-00061957.

Over the past several years the Commission has studied developments in retail and wholesale energy markets with the objective of developing a final version of these regulations, including the integration of the requirements of the Alternative Energy Portfolio Standards Act of 2004, 73 P.S. § 1648.1, et seq. We also initiated a separate investigation in 2006 to develop policy tools to mitigate the effect of potential electricity price increases. In addition to this policy statement, today we are issuing a final form rulemaking order for default service regulations, and our findings regarding proposals for addressing electricity price mitigation.

In reviewing the comments and considering the revisions to the proposed default service rules, the Commission recognized that there were practical limits to its regulation of large, complex energy markets. Requirements that might seem very appropriate today could be rendered obsolete by changes in markets, applicable law, or advances in technology. Accordingly, the Commission determined that some elements of the default service regulatory framework would be best addressed in the context of a policy statement that provides guidance to the industry as opposed to strict rules. A policy statement is more readily subject to change, and can provide needed flexibility to the Commission and market participants in the context of default service as energy markets continue to develop. The Commission anticipates that the initial guidelines will be applied to the first set of default service programs following the expiration of the generation rate caps, and these guidelines will be reevaluated prior to the filing of subsequent default service plans.

This policy statement, coupled with the default service regulations, and the order on electricity price mitigation, represents a comprehensive strategy for addressing retail
rates in the context of expiring rate caps and still developing retail and wholesale energy markets.


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43 The Industrial Energy Consumers of Pennsylvania, the Met-Ed Industrial Users Group, the Penelec Industrial Customer Alliance, the Philadelphia Area Industrial Energy Users Group, and the PP&L Industrial Customer Alliance.
DISCUSSION

In the following sections we will review each element of this policy statement.

A. § 69.1801. and § 69.1802. Statements of Scope and Purpose

Sections 69.1801 and 69.1802 identify the Commission’s objective for this policy statement. Given the rapid pace of change in wholesale energy markets, the Commission concludes that it would be unwise to craft a one size fits all approach at this time to every aspect of default service. These guidelines and the associated default service regulations will provide the necessary framework for default service providers (“DSPs”) and the Commission to manage the default service obligation.

B. § 69.1803. Definitions

For ease of reference, the Commission incorporates many of the default service regulation definitions at this section.

In response to comments from PPL and the Energy Association to the ANOFR and Proposed Policy Statement, the definitions of “default service provider” and “default service” have been revised. “Default service provider” has been changed to be consistent with the version found in the default service regulations and the definition of “default service” has been simplified.

C. § 69.1804. Default service program terms and filing schedules

In the rulemaking order for default service, we state that we are unable to identify the optimal program duration. There may be no standard program duration that is appropriate to all DSPs in all circumstances. Accordingly, we recommend two year
terms for all DSP programs following the initial filing. The Commission may modify this standard as markets mature.

D. § 69.1805. Electric generation supply procurement

The Commission has made the decision, at this time, not to mandate the statewide energy procurement model used by New Jersey. While this approach is attractive to many wholesale energy suppliers, given its administrative efficiencies and manifest transparency, we have concluded that each DSP should craft an approach best suited to its own service territory, within the framework provided herein. Also, our decision to encourage a portfolio approach with regular price adjustments does not readily lend itself to the application of the New Jersey model. Finally, we are not convinced that the New Jersey procurement approach for residential customers has resulted in the lowest prices attainable, produced meaningful market price signals, or allowed significant retail competition to develop for these customers at this time. However, as discussed in the default service regulations, the Commission will consider multi-territory procurement processes proposed by DSPs. However, such multi-territory procurements must incorporate the other aspects of this regulatory framework, including the regular adjustment of rates, flat rate design, etc.

We acknowledge that the recommendations found in this policy statement are guidelines, and not regulations. Accordingly, a DSP may propose procurement approaches that vary from those outlined in this policy statement. However, a DSP should be prepared to offer compelling evidence for taking an alternative approach. While we are giving DSPs some latitude in managing this obligation, we will be closely monitoring their performance. Should our experience lead us to conclude that too much discretion has been afforded to DSPs, we will revise the default service regulations and this policy statement accordingly.
Section 69.1805 encourages DSPs to consider a portfolio approach in managing their default service obligation. As discussed at length in the ANOFR, the Commission is cognizant of the risks associated with procuring all supply for several years or more at a single point in time. New Jersey has attempted to mitigate this risk by laddering the wholesale energy contracts used to satisfy basic generation service.

We also encourage the laddering of contracts. However, we also recommend that each DSP consider making multiple procurements over the course of a year, and to incorporate spot market purchases into their strategy. We suggest different procurement strategies for different customer classes, consistent with the level of energy knowledge, financial resources, and opportunity to shop associated with these groups.

E. § 69.1806. Alternative energy portfolio standard compliance

Many parties have asserted that the portfolio requirement of the Alternative Energy Portfolio Standards Act of 2004, 73 P.S. § 1648.1, et seq., cannot be satisfied without the use of long-term power purchase agreements (“PPA”) between DSPs and alternative energy suppliers. Without the ability to sell electricity through a long-term contract, some project developers may not be able to acquire needed investment to build these systems.

This is a problematic issue given the requirements of Section 2807(e)(3) of the Public Utility Code, 66 Pa.C.S. § 2807(e)(3), that supply for default service customers be acquired at “prevailing market prices.” The alternative energy portfolio requirement, as it impacts sales of electricity to retail customers after the expiration of generation rate caps, is a component of our regulation default service.
In Section 69.1806 of this proposed policy statement, the Commission observes that its default service regulations neither mandate nor prohibit long-term contracts. The term “long-term contract” is not readily subject to definition. A twenty to thirty year contract is certainly long-term. Some parties dispute whether a twenty to thirty year PPA can reflect prevailing market prices. We are reminded of our experience with PPAs approved by the Commission pursuant to the Public Utility Regulatory Policies Act of 1978. The rates negotiated for electricity under these PPA often diverged substantially from prevailing market prices over time. It is less clear whether contracts of shorter duration are as problematic.

F. § 69.1807. Competitive bid solicitation processes

This section includes an array of guidelines intended to improve competitive solicitation processes. In this section the Commission expresses its policy preferences on a range of issues. For example, the Commission recommends that load be procured for customer groupings (e.g., small customers vs. large customers), as opposed to slices of the DSP’s overall load.

We also identify several issues that will be referred to an existing proceeding, Standardization of Request for Proposal Documents and Supplier Master Agreements in the Context of Default Service, Docket No. M-00061960, for study and policy recommendations. This includes the development of uniform bidder qualification rules, standards for confidential bid information, etc. This working group should provide recommendations on these issues, and those previously assigned, to the Commission at a date to be determined by the Commission.

PSEG ERT recommended that the Commission consider the use of mechanisms that track and adjust default service rates in response to increases in transmission rates. PSEG ERT notes that if wholesale suppliers are at risk for increases in transmission rates,
they will include a risk premium in their competitive bids. The incorporation of a mechanism in a supplier master agreement (“SMA”) that allows these costs to be readily passed through may result in more competitive bids. PSEG ERT states that such a mechanism is used in the New Jersey Basic Generation Service SMA. We agree that this idea is worthy of further study, and have added Section 69.1807(9) to address it.

In response to a comment by Constellation, we have revised this section to clarify that while the standard SMAs will be revised, this will only be done on a going forward basis. Changes made to the Commission approved SMA language will not be applied retroactively to existing contracts.

Several parties provided comments in response to the ANOFR or the proposed policy statement regarding the public availability of information pertaining to winning bids. The OSBA and OCA in particular wished to clarify their access to this information. The Commission is reluctant to issue a uniform rule at this time without the benefit of a working group recommendation. We will work with the OCA and OSBA to responsibly address specific requests for data until a final policy is developed and approved.

G. § 69.1808. Default service cost elements

While utility rates were unbundled into transmission, distribution and generation components as part of the restructuring process, there is significant concern on the part of the Commission and others that some generation costs have been improperly allocated, or “embedded,” in EDC distribution rates. The Commission has not undertaken a full-fledged review of distribution rates with the goal of resolving this issue. This was in part due to the existence of rate caps and the agreements reached in the restructuring settlements. With the coming expiration of the remaining rate caps, there is now no
obstacle to taking this issue up for consideration.

Our preference is that this issue will be addressed in the next distribution rate case for each EDC. For those EDCs who have not initiated cases by the end of 2007, the Commission reserves the right to initiate a cost allocation proceeding to resolve this issue. We acknowledge that adjustments to rates will be deferred until the expiration of the EDCs’ effective rate caps.

In response to a comment from IECPA, we are revising this section to provide that congestion costs should generally be reflected in the fixed price bids submitted by wholesale energy suppliers. Accordingly, we would not expect congestion costs to be reconciled with regard to any fixed-price default service supply contracts.

In general, we are open to the concept of addressing the allocation of costs between generation and distribution rates through a collaborative process. We further agree that cost allocation should reflect the level of service, or lack of service, provided to default service and non-default service customers.

H. § 69.1809. Interim price adjustments and cost reconciliation

In the ANOFR, the Commission has revised the default service regulations to require regular price adjustments and to permit a DSP to reconcile its costs and revenues. Default service rates, which customers will more clearly understand through the use of a Price-to-Compare (‘‘PTC’’), will change during the term of a default service program for two reasons. First, prices will be adjusted to reflect changes in incurred costs due to the use of a portfolio approach. With a portfolio approach, DSPs will be acquiring electricity through multiple procurements, some of which may be laddered contracts or spot market energy purchases. As the term covered by the laddered contract or spot market energy
purchases expire, new contracts, most likely at different prices, will take effect. The PTC must be adjusted accordingly to reflect the change in costs.

Second, the PTC will need to be refined at an adjustment interval in order to reconcile default service costs and revenues. There will almost certainly be some variation between revenues received and costs incurred on a month to month basis. The Commission encourages the DSP to reconcile its rates at the regular PTC adjustment interval, similar to what a natural gas distribution company does with its gas rates. Specifically, the PTC should be recalculated to correct this divergence, and to eliminate undercollections or overcollections that have accumulated since the last PTC adjustment interval. The revised rate should be designed to eliminate these amounts by the time of the next adjustment.

This policy statement allows for interim adjustments, that is, a change in rates more frequently than at a normal adjustment interval, if there is a divergence greater than 4%. For example, a DSP may propose to revise the PTC for residential customers every quarter. In the event that incurred costs diverge from revenues by more than 4%, the DSP does not need to wait until the end of the quarter to revise its rates. It instead may file for an interim adjustment and recalculate the PTC.

In response to a comment from Constellation, we wish to clarify that the default service rate, and correspondingly the PTC, should be adjusted prospectively based on changes in the forecasted price of spot market supply products. The PTC should not be adjusted merely to reflect changes in the composition of a DSPs portfolio of energy products. However, the Commission will not be adjusting the suppliers’ winning bid prices in response to changes in wholesale energy markets.

We have also adjusted the threshold for interim reconciliation from 5% to 4% in response to the comments to the proposed policy statement.
I. § 69.1810. Retail rate design

The Commission finds that the PTC should reflect the cost of energy incurred, and that any disincentives to energy conservation should be eliminated from rate design. The final regulations expressly prohibit the PTC from being adjusted lower with increased customer usage. Accordingly, the design feature commonly known as “declining blocks” must be eliminated from default service rate design. The policy statement reaffirms this, and further provides that demand charges should be removed. We observe that Duquesne Light Company, in its most recent default service filing, is planning to discontinue all declining blocks and demand charges by 2010. Consistent with the final rulemaking order, we note that generation demand charges may be proposed for large commercial and industrial customers if the charges and rate determinants are reasonably related to the wholesale energy cost of providing default service.

J. § 69.1811. Rate change mitigation

The Commission recognizes that some customers may experience significant rate increases when the generation rate cap expires in their EDC’s service territory. This is more likely to occur in those territories where the generation rate has remained capped significantly below wholesale energy prices. The Commission finds it to be in the public interest that retail customers have reasonable opportunities to mitigate the effect of these price increases.

This policy statement recommends that DSPs give customers the option to defer paying some portion of a rate increase for a period of time in certain circumstances. Rather than adjusting a customer’s PTC to the full market price all at once, the PTC would be moved incrementally over a period of several years. The customer would also
gradually pay down the portion of the rate increase that was deferred. It must be
acknowledged that the DSP will incur some additional expense with this type of plan, as
its recovery of costs is being deferred. A customer who elects to defer some portion of
the rate increase will ultimately pay more for their electricity, analogous to paying
interest on a loan. Accordingly, we find that customers should have the choice to select
such an option, but should not be automatically assigned to such a plan. Those who have
the means and inclination to immediately pay market prices should be allowed to do so.

A DSP may propose other reasonable rate mitigation strategies for our
consideration. For example, a DSP might offer customers the option to pre-pay some
portion of an anticipated rate increase. Customers would be shown the current market
price of energy on their monthly bill, compared to the capped rate. They would then have
the option to pay the market price. This extra money would remain in the customer’s
account, plus accumulate interest, and be applied in the event that there was a significant
rate increase once the rate cap expired. If the increase was less than expected, the monies
could be refunded or credited to the customer’s bill. This process would have the added
benefit of educating consumers about market prices prior to the expiration of rate caps.

In response to a comment from PPL, we have clarified this section to state that the
rate mitigation calculation should be performed on a customer class basis, and not a
system-wide basis. A prepay or deferral option should be offered to those customer
classes whose total bill increase exceeds 25%.

We also agree with the comments of Con Edison and others that any mitigation
strategy be competitively neutral, and appreciate the examples of mitigation proposals
they and other parties recommend. Section 69.1811 has been drafted in a way to give the
Commission and companies some discretion in crafting reasonable mitigation plans.

We also recognize the challenges presented by rate increase deferrals, including
the fact that customers ultimately pay more due to carrying charges. Accordingly, we emphasize that customers must affirmatively select such options to be enrolled. We would expect that customers would have to contact their DSP by phone or electronic mail, or sign and return some written authorization to the DSP, in order to enroll in such a program.

In response to a comment of Citizens and Wellsboro, we confirm that this provision does not apply to EDCs whose generation rate cap has already expired. These customers are already paying market based rates.

**K. §§ 69.1812 – 69.1817. Retail Market Issues**

In these sections the Commission provides guidelines on the integration of default service with the competitive retail market. The Commission has identified a number of issues where opportunities exist to enhance customer choice and facilitate the development of retail markets. Robust, effective markets are vital element of any post-rate cap price mitigation strategy.

We are referring each issue identified in these sections to the Retail Markets Working Group for study and policy recommendations. Commission staff should convene this working group within 45 days of the publication of this final policy statement in the Pennsylvania Bulletin. Within a reasonable period of time after convening the group, Commission staff will propose a schedule to the Commission for the development of policy recommendations. Our expectation is that the activities of this working group will be completed well before the expiration of the remaining generation rate caps.

We also find that customer education is a vital component of fostering effective retail markets. Consumer education plans that address retail choice will be required
pursuant to an order we are issuing in the price mitigation proceeding at Docket M-00061957.

Section 69.1812 has been edited at the recommendation of the OCA to emphasize that proper consideration be given to protecting private or sensitive customers information.

In response to a comment by RESA and Hess to the proposed policy statement, we are amending Section 69.1813, to require consideration of “bill ready” billing in addition to rate ready billing in all DSP service territories.

As a general response to the comments to these provisions, the Commission will consider the costs of implementing these policies. We believe that these policies, if properly designed, can serve the public interest. However we recognize that it may not be in the public interest to adopt all of these policies in all EDC service territories.

Finally, we will be monitoring the implementation of the purchase of receivables program in the Duquesne territory. As the OCA noted, this program was adopted in lieu of fully and finally addressing the issue of embedded generation costs in distribution rates. As an interim step in responding to Section 69.1808, other EDCs may wish to consider proposing similar programs for Commission review and approval.

**CONCLUSION**

The Commission will closely monitor the implementation of this policy statement and the associated default service regulations by DSPs. The policy statement will be revised based on experience gained from future proceedings. Over time, we may find it appropriate to move some elements of this policy statement to the default service
Unlike the default service regulations, this policy statement does not require additional regulatory approvals to become effective. However, we will delay publication of this policy statement in the Pennsylvania Bulletin until the default service regulations have been approved by Pennsylvania General Assembly, the Independent Regulatory Review Commission and the Pennsylvania Attorney General. Should these agencies require amendments to the regulations, this policy statement may need to be revised. Accordingly, this policy statement will not be published and take effect until after the default service regulations have received all regulatory approvals; THEREFORE,

**IT IS ORDERED:**

1. That the regulations of the Commission at 52 Pa. Code Chapter 69 are amended by adding a statement of policy at §§ 69.1801 – 69.1817 as set forth in Annex A.

2. That the Secretary shall submit this order and Annex A to the Governor's Budget Office for review of fiscal impact.

3. That the Secretary shall certify this order and Annex A. This order and Annex A will be deposited with the Legislative Reference Bureau for publication in the *Pennsylvania Bulletin* after the regulations promulgated at Docket L-00040169 have obtained all regulatory approvals.

4. That this Policy Statement shall be come effective upon publication in the *Pennsylvania Bulletin.*
5. That alternative formats of this document are available to persons with disabilities and may be obtained by contacting Sherri Delbiondo, Regulatory Coordinator, at (717) 772-4597.

6. That the contact person for this matter is Shane Rooney, (717) 787-2871, srooney@state.pa.us.

7. That Commission staff convene the Retail Markets Working Group within 45 days of the publication of the Final Policy Statement in the Pennsylvania Bulletin, consistent with the instructions given in this order.

BY THE COMMISSION

James J. McNulty
Secretary

(SEAL)

ORDER ADOPTED: May 10, 2007

ORDER ENTERED: May 10, 2007
§ 69.1801. Statement of scope.

Sections 69.1802 – 69.1817 provide guidelines to default service providers regarding the acquisition of electric generation supply, the recovery of associated costs and the integration of default service with competitive retail electric markets.

§ 69.1802. Statement of purpose.

(a) The Commission has adopted regulations governing the default service obligation in §§ 54.181-189 (relating to default service), as required by 66P Pa.C.S. § 2807(e) (relating to the duties of electric distribution companies). The regulations address the elements of a default service regulatory framework. The goal of default service regulations is to bring competitive market discipline to historically regulated markets. This can be accomplished by structuring default service in a way that encourages the entry of new retail and wholesale suppliers. Greater diversity of suppliers will benefit ratepayers and the Commonwealth. However, these rules are not designed to resolve every possible issue relating to the acquisition of electric generation supply, the
recovery of reasonable costs, the conditions of service, and the relationship with the competitive retail market.

(b) The Commission is very cognizant of the practical limits of regulating large, complex markets. Changes in Federal or State law, improvements in technology, and developments in wholesale energy markets may render obsolete any all-inclusive regulatory approach to this Commonwealth’s retail electric market.

(c) The Commission has devised an approach that will allow this Commonwealth to adapt to changes in energy markets and the regulatory environment. The regulations codified at Chapter 54 (relating to electric generation customer choice) will serve as a general framework for default service and provide an appropriate measure of regulatory certainty for ratepayers and market participants. This section and §§ 69.1801 and 69.1803 – 69.1817 will provide guidelines on those matters when a degree of flexibility is required to respond effectively to regulatory and market challenges. The Commission anticipates that the initial guidelines will be applied to the first set of default service plans following expiration of the generation rate caps, and that the guidelines will be reevaluated prior to the filing of subsequent default service plans.

§ 69.1803. Definitions.

The following words and terms, when used in this section and §§ 69.1801, 69.1802 and 69.1804 – 69.1817, have the following meanings, unless the context clearly indicates otherwise:

*Alternative energy portfolio standards* – A requirement that a certain percentage of electric energy sold to retail customers in this Commonwealth by EDCs and EGSs be derived from alternative energy sources, as defined in the Alternative Energy Portfolio Standards Act (73 P.S. §§ 1648.1 – 1648.8).
**Competitive bid solicitation process** – A fair, transparent, and non-discriminatory process by which a DSP awards contracts for electric generation to qualified suppliers who submit the lowest bids.

**DSP – Default service provider** – The incumbent EDC within a certificated service territory or a Commission approved alternative default service provider SUPPLIER OF ELECTRIC GENERATION SERVICE.

**Default service** –

(i) Electric generation supply service provided by a DSP to a retail electric customer who is not receiving generation service from an EGS.

(ii) Electric generation supply service provided pursuant to a Commission approved default service plan.

**ELECTRIC GENERATION SUPPLY SERVICE PROVIDED PURSUANT TO A DEFAULT SERVICE PROGRAM TO A RETAIL ELECTRIC CUSTOMER NOT RECEIVING SERVICE FROM AN EGS.**

**Default service implementation plan** – The schedule of competitive bid solicitations and spot market purchases, all technical requirements, and all related forms and agreements.

**Default service procurement plan** – The electric generation supply acquisition strategy the DSP will utilize in satisfying its default service obligations, including the manner of compliance with the alternative energy portfolio standards requirement.

**Default service program** – A filing submitted to the Commission by the DSP that identifies a procurement plan, an implementation plan, a rate design to recover all reasonable costs, and all other elements identified in § 54.185 (relating to default service implementation plans and terms of service).

**EDC – Electric distribution company** – The term has the same meaning as defined in 66 Pa.C.S. § 2803 (relating to definitions).

**EGS – Electric generation supplier** – The term has the same meaning as defined in 66 Pa.C.S. § 2803.
Maximum registered peak load – The highest level of demand for a particular customer, based on the PJM Interconnection, LLC, peak load contribution standard, or its equivalent, and as may be further defined by the EDC tariff in a particular service territory.

PTC – Price-to-compare – The rate charges to a retail electric customers by the DSP for default service. A LINE ITEM THAT APPEARS ON A RETAIL CUSTOMER’S MONTHLY BILL FOR DEFAULT SERVICE. THE PTC IS EQUAL TO THE SUM OF ALL UNBUNDLED GENERATION AND TRANSMISSION RELATED CHARGES TO A DEFAULT SERVICE CUSTOMER FOR THAT MONTH OF SERVICE.

Prevailing market prices – Prices that are available in the wholesale market at particular points in time for electric generation supply.

RTO – Regional transmission organization – A Federal Energy Regulatory Commission (FERC)-approved regional transmission organization.

Retail customer or retail electric customer – These terms have the same meaning as defined in 66 Pa.C.S. § 2803.

Spot market energy purchase – The purchase of an electric generation supply product in a FERC-approved real time or day ahead energy market.

§ 69.1804. Default service program terms and filing schedules.

The default service regulations provide for a standard initial program term of 2 to 3 years. Initial programs may vary from this standard to comply with the applicable regional transmission organization planning year. Subsequent programs should be for 2 years, unless otherwise directed by the Commission. The Commission will monitor developments in wholesale or retail markets and revisit this issue as appropriate. The Commission may revise the duration of the standard program term and program filing schedules based on market developments.
§ 69.1805. Electric generation supply procurement.

A proposed procurement plan should balance the goals of allowing the development of a competitive retail supply market and also including a prudent mix of arrangements to minimize the risk of over-reliance on any particular source of energy products at a particular point in time. In developing a proposed procurement plan, a DSP should consider including a prudent mix of supply-side and demand-side resources such as long-term, short-term, staggered-term and spot market purchases to minimize the risk of contracting for supply at times of peak prices. Long-term contracts should only be used when necessary and required for DSP compliance with alternative energy requirements, and should be restricted to covering a relatively small portion of the default service load. An over-reliance on long-term contracts would mute demand response, create the potential for future default service customers to bear future above market costs, and limit operational flexibility for DSPs to manage their default service supply. The plan should be tailored to the following customer groupings, but DSPs may propose alternative divisions of customers by registered peak load to preserve existing customer classes.

(1) Residential customers and non-residential customers with less than 25 kW in maximum registered peak load. Initially, the DSP should acquire electric generation supply for these customers using a mix of resources as described in the introductory paragraph to this section. Consideration should be given to procuring most fixed-term supply through full requirements or block contracts of 1 to 3 years in duration. Contracts should be laddered to minimize risk, in which a portion of the portfolio changes at least annually, with a minimum of two competitive bid solicitations a year to further reduce the risk of acquisition at a time of peak prices. In subsequent programs, the percentage of supply acquired through shorter duration full requirements contracts and spot
market purchases should be gradually increased, depending on developments in retail and wholesale energy markets.

(2) **Non-residential customers with 25-500 kW in maximum registered peak load.** The DSP should acquire electric generation supply for these customers using a mix of resources as described in the introductory paragraph to this section. Fixed-term contracts should be 1 year in length and may be laddered to minimize risk, with a minimum of two competitive bid solicitations a year to further reduce the risk of acquisition at a time of peak prices. In subsequent programs, the percentage of supply acquired through shorter duration purchases and spot market purchases should gradually be increased, depending on developments in retail and wholesale energy markets.

(3) **Nonresidential customers with greater than 500 kW in maximum registered peak load.** Hourly priced or monthly-priced service should be available to these customers. The DSP may propose a fixed-price option for the Commission’s consideration.

§ 69.1806. **Alternative energy portfolio standard compliance.**

In procuring electric generation supply for default service customers, the DSP shall comply with the Alternative Energy Portfolio Standards Act (73 P.S. §§ 1648.1 – 1648.8). The Commission’s default service regulations neither prohibit nor mandate the use of long-term contracts to satisfy the alternative energy portfolio standards obligation. In satisfying this obligation, a DSP’s procurement strategy should reflect the incurrence of reasonable costs.

The following guidelines will apply to competitive bid solicitation processes:

(1) DSPs should use standardized request for proposal documents and supplier master agreements approved by the Commission for use in the default service procurements. The Commission will review these documents and agreements on a regular basis and revise them when appropriate after consultation with stakeholders. **REVISIONS TO THESE DOCUMENTS WILL NOT BE APPLIED RETROACTIVELY TO EXISTING CONTRACTS.**

(2) The public interest would be served by the adoption of uniform criteria and processes for bidder qualification.

(3) Competitive bid solicitations should be structured along customer classes, consistent with the groupings identified in § 69.1804 (relating to default service programs and filing schedules § 69.1805 (RELATING TO ELECTRIC GENERATION SUPPLY PROCUREMENT). Bids should be solicited for tranches of load within each customer class. Slice of system bid designs should not be utilized. **HOWEVER, DSPS MAY ALLOW INDIVIDUAL TRANCHES TO BE STRATIFIED BY SOLICITING SEPARATE BID PRICES FOR RESIDENTIAL, COMMERCIAL AND INDUSTRIAL SEGMENTS WHEN THERE ARE TOO FEW CUSTOMERS TO ORGANIZE TRANCHES ALONG THE GROUPINGS IDENTIFIED AT § 69.1805.**

(4) The Commission finds that a clearly optimal bid solicitation model does not exist at the current stage of wholesale market development. DSPs may utilize various competitive bid solicitation approaches, including request for proposals that result in the submission of sealed bids and real time auctions in which energy suppliers compete with each other for tranches of customer load.

(5) DSPs are encouraged to coordinate their competitive bidding solicitation schedules to minimize conflicts that might negatively affect the ability of suppliers to participate in multiple procurements. **DSPs SHOULD COORDINATE THEIR**
BID CONFERENCES AND BIDDING DATES TO FACILITATE BID PARTICIPATION AND ECONOMIES OF SCALE, YET ALSO PROVIDING OPPORTUNITIES FOR ADDITIONAL WHOLESALE BIDDING OVER REASONABLE TIME INTERVALS with loads of greater than 50 megawatts should avoid scheduling pre-bid conferences, auctions, and the like, on the same day as other DSPs with loads greater than 50 megawatts.

(6) The Commission’s objective is to review the results of competitive bidding processes in a manner sensitive to market dynamics but that also allows it to discharge its statutory obligations. The Commission recognizes that bid prices may be negatively affected by the length of time taken for Commission review. In the default service regulations, the Commission has reserved a period of 1 business day to review the results of competitive procurements. As retail and wholesale markets mature, and as other appropriate safeguards become available, the Commission may elect to reduce the amount of time it uses to review bidding results.

(7) The public interest would be served by the adoption of uniform rules for the confidentiality of competitive solicitation information. Supplier participation, bid prices, and retail rates may be impacted by protecting certain information, including, the identity of winning and losing bidders, the number of bids submitted, bid prices, the allocation of load among winning bidders, and the like. At the same time, the Commission recognizes that there is a legitimate public interest in knowing some of this information when there is no possibility of any prejudice to ratepayer interests.

(8) The competitive bid solicitation process will be monitored by an independent evaluator. The Commission may direct that this evaluator administer competitive bid solicitations to ensure the independence of the process. This independent party will be selected by the DSP in consultation with the Commission. The DSP may not have an ownership interest in the evaluator, and vice versa, and the DSP should disclose any potential conflicts of interest on the
part of the evaluator during this consultation process. The Commission will review conflicts of interest and may disqualify an evaluator in order to ensure the independence of the position. The evaluator should have an expertise in the analysis of wholesale energy markets, including methods of energy procurement. The evaluator should monitor compliance with Commission orders relating to a default service program, confidentiality agreements, and other directives. The evaluator should report all information it obtains to the Commission.

(9) WHOLESALE ENERGY SUPPLIERS MAY INCLUDE A SIGNIFICANT RISK PREMIUM IN THEIR COMPETITIVE BIDS TO HEDGE AGAINST CHANGES IN TRANSMISSION RATES DURING THE TERM OF A DEFAULT SERVICE SUPPLY CONTRACT. THE PUBLIC INTEREST WOULD BE SERVED BY CONSIDERATION OF MECHANISMS THAT ALLOW FOR THE TRACKING AND AUTOMATIC ADJUSTMENT OF TRANSMISSION RATES DURING THE TERM OF THE DEFAULT SERVICE SUPPLY CONTRACT IN ORDER TO REDUCE THIS PREMIUM.

§ 69.1808. Default service cost elements.

(a) The PTC should be designed to recover all generation, transmission and other related costs of default service. These cost elements include:

(1) Wholesale energy, capacity, ancillary, congestion, applicable RTO or ISO administrative, and transmission costs.

(2) CONGESTION COSTS WILL ULTIMATELY BE RECOVERED FROM RATEPAYERS. CONGESTION COSTS SHOULD BE REFLECTED IN THE FIXED PRICE BIDS SUBMITTED BY WHOLESALE ENERGY SUPPLIERS.
(2)(3) Supply management costs, including supply bidding, contracting, hedging, risk management costs, any scheduling and forecasting services provided exclusively for default service by the EDC, and applicable administrative and general expenses related to these activities.

(3)(4) Administrative costs, including billing, collection, education, regulatory, litigation, tariff filings, working capital, information system and associated administrative and general expenses related to default service.

(4)(5) Applicable taxes, excluding sales tax.

(5)(6) Costs for alternative energy portfolio standard compliance.

(b) EDC rates should be scrutinized for any generation related costs that remain embedded in distribution rates. This review should occur no later than the next distribution rate case for each EDC filed after _______ (Editor’s Note: The blank refers to the effective date of adoption of this statement of policy.). The Commission may initiate a cost allocation case for an EDC on its own motion if such a case is not initiated by December 31, 2007. Changes to rates resulting from such examination would take effect after the expiration of Commission-approved rate caps.

§ 69.1809. Interim price adjustments and cost reconciliation.

(a) Consistent with the default service regulations, the PTC DEFAULT SERVICE RATES, AND CORRESPONDINGLY THE PTC, will be adjusted on a regular basis to reflect changes in and ensure the recovery of reasonable costs resulting from changes in wholesale energy prices or other costs FROM THE INTRODUCTION OF NEW, DIFFERENTLY PRICED ENERGY SUPPLY PRODUCTS TO THE DSP’S PORTFOLIO, AND TO CORRECT THE UNDER AND OVER COLLECTION OF COSTS. For example, the PTC will be adjusted at least every quarter for residential customers and at least every month for large business customers.
This PTC adjustment may be driven by changes in spot market prices, the use of laddered contracts, the use of seasonal rate design, and the like.

(b) The public interest may be served if default service AND ALTERNATIVE ENERGY COMPLIANCE costs and the revenues received through default service rates are reconciled as part of the PTC adjustment process. Reconciliation would ensure that DSPs fully recover their actual, incurred costs without requiring customers to pay more than is required. The PTC adjustment will therefore also reflect changes required due to the reconciliation of costs and revenues. Reconciliation proposals should result in a PTC adjustment that will resolve cumulative under or over collections RECOVERIES by the time of the next PTC adjustment interval.

(c) It may be in the public interest to reconcile default service costs more frequently than at each PTC adjustment interval. The DSP should propose interim reconciliation prior to the next subsequent PTC adjustment interval when current monthly revenues have diverged from current monthly costs, plus any cumulative over/under recoveries, by greater than 5% 4% since the last rate adjustment. When the divergence is less than 5% 4%, the DSP has the discretion to propose interim reconciliation prior to the next PTC adjustment interval. Interim reconciliation proposals should result in a PTC adjustment that will resolve cumulative under or over collections RECOVERIES by the time of the next PTC adjustment interval.

§ 69.1810. Retail rate design.

Retail rates should be designed to reflect the actual, incurred cost of energy and therefore encourage energy conservation. The PTC should not incorporate declining blocks, demand charges, or similar elements. The PTC for a particular customer class may be converted to a time of use design if the Commission finds it to be in the public interest.
§ 69.1811. Rate change mitigation.

(a) The following provision should apply when a DSP’s total retail rate FOR A CUSTOMER CLASS rises by more than 25% following the expiration of a generation rate cap due to wholesale energy prices. WHEN THAT OCCURS, DSPs should offer all residential and small business customers of up to 25 kW in maximum registered peak load the opportunity to prepay or defer some portion of the rate increase for as long as 3 years. These COMPETITIVELY NEUTRAL mitigation options should be included in the default service program filed for the period that begins with the expiration of the Commission-approved generation rate cap. Customers may not be assigned to a rate increase prepay or deferral program without their affirmative consent. DSPs would be able to fully recover the reasonable carrying costs associated with a rate increase deferral program, including associated administrative costs.

(b) DSPs may propose other reasonable rate mitigation strategies that would reflect the incurrence of reasonable costs.

§ 69.1812. Information and data access.

The public interest would be served by common standards and processes for access to retail electric customer information and data. This includes customer names and addresses, customer rate schedule and profile information, historical billing data, and real time metered data. Retail choice, demand side response, and energy conservation initiatives can be facilitated if EGSs, curtailment service providers, and other appropriate parties can obtain this information and data under reasonable terms and conditions common to all service territories, WITH THAT GIVE due consideration given to customer privacy, PROVIDE SECURITY OF INFORMATION, AND PROVIDE A
CUSTOMER AN OPPORTUNITY TO RESTRICT ACCESS TO NON-PUBLIC CUSTOMER INFORMATION.

§ 69.1813. Rate AND BILL ready billing.

The public interest would be served by the consideration of the availability of rate AND BILL ready billing in each service territory.

§ 69.1814. Purchase of receivables.

The public interest would be served by the consideration of an EGS receivables purchase program in each service territory.

§ 69.1815. Customer referral program.

The public interest would be served by consideration of customer referral programs in which retail customers are referred to EGSs.

§ 69.1816. Supplier tariffs.

The public interest would be served by the adoption of supplier tariffs that are uniform as to both form and content. Uniform supplier tariffs may facilitate the participation of EGSs in the retail market of this Commonwealth and reduce the potential for mistake or misunderstandings between EGSs and EDCs.

§ 69.1817. Retail choice ombudsman.

The public interest would be served by the designation of an employee as a retail choice ombudsman at each EDC and the Commission. The ombudsman would be responsible for responding to questions from EGSs, monitoring competitive market
complaints and facilitate FACILITATING informal dispute resolution between the DSP and EGSs.
Appendix 3 – Mitigation Order
PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, PA 17105-3265

Public Meeting held May 10, 2007

Commissioners Present:

Wendell F. Holland, Chairman, Concurring and Dissenting Statement attached
James H. Cawley, Vice Chairman
Kim Pizzigrilli
Terrance J. Fitzpatrick

Policies to Mitigate Potential Electricity
Price Increases

Docket No. M-00061957

FINAL ORDER

BY THE COMMISSION:

On May 19, 2006, the Commission commenced this proceeding to develop policies to address potential electric rate increases that follow the expiration of generation rate caps. The Commission presided over an En Banc hearing on June 22, 2006, and solicited public comments on appropriate price mitigation strategies. On February 8, 2007, the Commission issued a Tentative Order that identified proposed policies for addressing rising energy costs. Public comments were requested on these tentative findings. The Commission has reviewed these comments and now issues a final order.

Comments were filed in response to the Tentative Order by Citizens for Pennsylvania’s Future (“PennFuture”), Comperio Energy, LLC (“Comperio”), Constellation NewEnergy, Inc. and the Constellation Energy Commodities Group, Inc.

DISCUSSION

In the following sections, the Commission will review comments to the Tentative Order and identify its findings.

A. Consumer Education

1. Comments to the Tentative Order

The Commission’s tentative findings on consumer education elicited more comments than any other issue addressed in the Tentative Order. Comperio, Constellation, Duquesne, Hess, the ECA, FirstEnergy, IECPA, Maureen Mulligan, NEM, PECO, OCA, OSBA, PennFuture, PPL, PULP, RESA, and UGI. Parties agreed that consumer education was an essential element of a price mitigation strategy, that EDCs

44 Comments to the Tentative Order are available on the Commission’s public internet domain at: http://www.puc.state.pa.us/electric/electric_enbanc_price_comments.aspx. Other parties addressed aspects of the Tentative Order within comments filed in response the Commission’s recent orders on default service.
should implement education programs, and that EDCs could recover the reasonable costs of education programs from ratepayers.

However, the parties asked that the Commission revise or reassess its proposed education measures in a number of ways. First, parties such as Duquesne, UGI and OSBA asked that the Commission reconsider the need for a statewide education campaign in service territories in which the generation rate cap has already expired. These parties questioned whether it would be equitable for their customers to pay for education programs about the end of rate caps when they have already been paying market based rates for several years.

Some parties also had concerns about the proposed $5 million budget of the statewide campaign. PennFuture, the ECA and Maureen Mulligan all believe that a significantly larger budget is required if the programs are to be effective. Overall budgets of $10 to $25 million were recommended. RESA and the OSBA also questioned whether the proposed budget was adequate.

Many parties recommended that Council for Utility Choice (“CUC”) membership be adjusted to be more fully representative of current retail electric customer, energy supplier and EDC interests. Constellation, the OSBA, Duquesne, FirstEnergy were among those who identified this concern. Some parties emphasize that the CUC can serve an important advisory role, but that the important work of implementing a statewide campaign should be done by professionals with some expertise in these matters. UGI, the ECA and Maureen Mulligan believe that Commission should look to the private sector for assistance. UGI and the ECA recommended that the Commission issue a request for proposal to obtain these services.

45 Some parties commented that as the Gas Association of Pennsylvania is defunct, that other parties be substituted. The Tentative Order incorrectly identified the Gas Association as still having a seat on the CUC. The Energy Association of Pennsylvania was given two seats in its stead.
Numerous suggestions were offered regarding the objectives of a statewide education campaign. NEM, Hess and RESA focused on the importance of effective education about customer choice. For example, RESA recommended that a website be developed that provides retail customers current, accurate information about retail choice options in their service territories. RESA believes that the current Pennsylvania utility choice website is ineffective and identified websites for New York and Texas as appropriate models.

A variety of recommendations were offered regarding the objectives and design of any new education programs. Some parties believe that more emphasis should be placed on energy efficiency and conservation. Others emphasized that customers be informed about practical steps that they can take and that less emphasis be given to the reasons for price changes and the nature of energy markets. The OCA stressed that those customers served by EDCs under rate caps must clearly understand when their cap is expiring, so that they can begin to take measures now to reduce the size of their future bills.

Finally, most parties asked the Commission to revise its proposed findings on the allocation and recovery of costs for the proposed consumer education initiative. While parties generally accept that EDCs may recover reasonable costs from ratepayers, many objected to using the customer assistance program surcharge as the mechanism. These parties believe that this surcharge should be restricted to recovering universal service costs, and should only be applied to residential customers. Parties instead recommended that EDCs be given some discretion in using either tariff riders or base rates to recover reasonable education costs.

There was disagreement on the allocation of costs among different customer classes. The OCA recommended that all customer classes be responsible for some portion of the costs of any statewide campaign. Conversely, PECO recommended that education be focused on residential customers, and that costs therefore do not need to be
collected from other customer classes. The OSBA asserted that if small business customers are assessed for these costs, that large commercial and industrial customers should pay as well.

2. Findings

a. Overview

Virtually all parties who spoke at the En Banc hearing and filed comments in 2006 agreed that consumer education is an essential element of any strategy to mitigate the effect of price increases. However, there was a significant disagreement over the size and scope of these efforts. Having considered all comments, the Commission will adopt the following plan:

Each electric distribution company ("EDC") shall file a consumer education plan for its service territory with the Commission for approval by December 31, 2007.

The Office of Communications, with the assistance of Commission staff, and interested stakeholders, will develop and implement a statewide education campaign funded by EDC assessments.

The Commission will use its authority under the Public Utility Code to assess EDCs for the costs of a statewide campaign, and seek approval of these costs from the Governor and Pennsylvania General Assembly as part of its budget request.
b. EDC Consumer Education Plans

The Commission shares the nearly unanimous sentiment of those who participated in this proceeding that consumer education is a vital element of any plan to mitigate price increases. Therefore, EDCs will implement consumer education plans tailored to their service territories that will help retail customers mitigate the effect of wholesale energy price increases. Plans should be designed to increase ratepayer knowledge about a variety of issues. The best education plans should give consumers practical advice about preparing for and reducing the costs of their bills. EDC plans will be evaluated according to how they communicate the following “Energy Education Standards” to customers:

- The generation component of retail electric rates charged to customers by electric utilities has been capped since 1996, and that the cap for that customer’s service territory will expire on _______ (as per territory).

- The rate charged for generation service will change after the rate cap expires, and may significantly increase.

- Customers can take certain steps before the expiration of the rate cap, and other steps at the time the rate caps expire, that may help them control the size of their electric bills.

- Customers can control the size of their electric bills through energy efficiency, conservation and demand side response measures. Customers can benefit from utilizing these measures now, even if the rate cap is still in effect where they reside.

- Cost-effective energy efficiency, conservation and demand side response programs and technologies have been identified and information about them is readily available.

- Customers may reduce the size of their electric bills, or receive service options more suited to their needs, by purchasing generation service from an alternative electric generation supplier.

46 “Require each utility to file a plan to complete the transition that parties can critique and the PUC can approve, modify or reject. Each plan should cover key issues like consumer education…” PennFuture comments.
Current information that will allow customers to make informed choices about competitive generation alternatives is readily available. In territories where there are not competitive offerings currently, more choices may be available once rate caps expire.

Programs exist to help low income customers maintain their utility service, and information about them is readily available.

Accordingly, customers should know when the rate cap in their service territory is ending. Customers should understand that there are conservation, energy efficiency and DSR options and technologies available to them, and how to take advantage of them. We also agree that competitive choice options can be more effectively communicated to retail customers. EDCs should also evaluate how they are currently informing their customers about the availability of programs for those with limited incomes.

EDC programs and the statewide campaign should reasonably complement the other in achieving these standards. Accordingly, in evaluating EDC proposals, the Commission will strive to harmonize elements of the individual plans and the statewide campaign. However, the Commission will allow plans to be tailored to the particular circumstances of a service territory.47

In formulating proposals, the Commission encourages EDCs to give some emphasis to their efforts to reach more vulnerable portions of their customer base. Accordingly, the utility-specific and statewide campaigns should focus on outreach to the following segments of their customer base:

- Residential energy customers
  - African-American and Latino markets
  - Senior citizens

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47 “Each electric utility company in Pennsylvania has specific messages that need to be conveyed to their customers. One size does not fit all.” $1 Energy Fund comments.
People in the households responsible for reviewing and paying utility bills
- Low income households
- Rural households
- School-aged children

Small business customers

Accordingly, each EDC shall file a consumer education plan with the Commission for review and approval by December 31, 2007. The plan should document programs and an implementation schedule to address the Energy Education Standards we have identified. The Commission recognizes that some EDCs have existing programs that address some or all of these Energy Education Standards. These programs may be incorporated into the plans to be filed with the Commission.

We encourage EDCs to consider long term education strategies, and to propose plans that will be in effect for at least five years. By the end of that period the transition to market prices for all territories will be complete, and all market participants regulated by the Commission will be complying with default service rules, alternative energy portfolio standards, and other pending energy initiatives. At that point EDC education plans can be reevaluated and revised accordingly, based on market conditions and retail customers’ level of knowledge and response to these programs.

Given the great differences that exist in size and load profile across service territories, the Commission will not recommend specific budget levels for each company. EDCs should propose a budget that will adequately address the Energy Education Standards we have identified. A specific cost-recovery mechanism should be proposed as an element of each filing.

The Commission recognizes that a different emphasis is needed in service territories where customers are now paying market based rates. As Duquesne and UGI have noted, their and some other EDCs’ generation rate caps have already expired.
Accordingly, we do not expect those EDCs to address the expiration of rate caps in their consumer education plans. The Commission accepts that these companies will focus on practical steps customers can take to reduce the size of their electric bills through energy conservation and retail choice.

c. Statewide Education Campaign

The Commission received comments for and against a statewide consumer education campaign prior to the issuance of the Tentative Order. The Commission acknowledges that the EDC specific education plans may be the most effective way of reaching consumers, given that they can be customized for each territory. However, we find that a statewide campaign, if done appropriately, can complement and reinforce EDC education programs. Accordingly, we will implement a statewide education campaign to address the same Energy Education Standards identified for the EDC programs:

The generation component of retail electric rates charged to customers by electric utilities has been capped since 1996, and that the cap for that customer’s service territory will expire on _______ (as per territory).

The rate charged for generation service will change after the rate cap expires, and may significantly increase.

Customers can take certain steps before the expiration of the rate cap, and other steps at the time the rate caps expire, that may help them control the size of their electric bills.

48 “The Commission can play an important role in educating customers, particularly residential customers and low income customers, about how electricity markets work, the factors that contribute to energy prices, and how customers can help manage their energy prices. The Commission has in the past, and can again, play an important role in educating customers about their ability to select alternative suppliers and about simple conservation measures.” Constellation Energy Group comments; “Consumer education can have a statewide component (broad messages) and a local component (messages tailored to an individual EDC’s rates). comments filed by PPL Electric Utilities Corporation; “While Allegheny believes that the Commission should provide EDCs its input for standardization and uniformity of consumer education approaches, the Commission should not undertake a statewide program.” Allegheny Power comments.
Customers can control the size of their electric bills through energy efficiency, conservation and demand side response measures. Customers can benefit from utilizing these measures now, even if the rate cap is still in effect where they reside.

Cost-effective energy efficiency, conservation and demand side response programs and technologies have been identified and information about them is readily available.

Customers may reduce the size of their electric bills, or receive service options more suited to their needs, by purchasing generation service from an alternative electric generation supplier.

Current information that will allow customers to make informed choices about competitive generation alternatives is readily available. In territories where there are not competitive offerings currently, more choices may be available once rate caps expire.

Programs exist to help low income customers maintain their utility service, and information about them is readily available.

The statewide campaign could educate retail customers about these standards using television, radio, billboards, newspapers and paid sponsorships on cable and public television shows; media relations; “PUC on the Road” events statewide; community consumer-education events and summits; regional small business energy expos, a special website; a new brochure on responsible use of energy; public dissemination of information and comparisons related to electricity prices; paid traffic radio partnerships on conservation that could be updated during heat waves; outreach to community and business organizations; youth-related activities; and a survey measuring the effectiveness of the efforts. The statewide campaign would include the same emphasis on the vulnerable segments of the customer base addressed in EDC specific plans.

The statewide campaign would be funded by a $5 million assessment collected from EDCs. Under Section 510(a) of the Public Utility Code, 66 Pa.C.S. § 510(a), the Commission is required before November 1 of each year to submit a budget request,
containing an estimate of its costs to administer the Public Utility Code, to the Governor and the General Assembly. Subsections (b) and (c) of Section 510 establish the process by which utilities are assessed to pay their share of the operating costs of the Commission. 66 Pa.C.S. §§ 510(b), (c). Since the costs to conduct a statewide consumer education campaign would be costs incurred by the Commission to implement the Public Utility Code, these costs must be submitted for approval by the Governor and General Assembly as part of the Commission’s budget request. In addition, to the extent that the consumer education costs are authorized as part of the Commission’s budget, these costs must be assessed to electric utilities under the process set forth in §510(b) and (c). The Commission will comply with these procedures in implementing a statewide consumer education campaign.

With respect to the issue of cost recovery by electric utilities, we agree with the parties who commented that a surcharge for “universal service and energy conservation” is not an appropriate recovery mechanism because this statewide consumer education effort is not intended exclusively for low income customers.49 Since the costs of the statewide campaign will be included in the annual assessments to utilities under 66 Pa.C.S. § 510, the utilities may recover these costs from customers in the same manner as they recover other costs assessed by the Commission. In the alternative, utilities may propose a different recovery mechanism as part of their consumer education plan filing.

While we believe it is appropriate for the Commission to obtain the views of interested parties regarding the statewide consumer education campaign, we do not find it necessary to reactivate the CUC. Rather, the Office of Communications will be charged with developing the statewide campaign in consultation with interested stakeholders. In order to begin this process, the Office of Communications will convene the interested

49 “Universal service and energy conservation” is defined in the Competition Act as “policies, protection and services that help low-income customers to maintain electric service.” 66 Pa.C.S. § 2803.
stakeholders within sixty days of entry of the Final Order to help establish the groundwork for this effort in anticipation of approval in next year’s budget.

We expect that the Office of Communications and stakeholders will develop recommendations regarding the scope, objectives, duration, budget, design and cost-recovery for a statewide campaign. In addressing the scope of the campaign, the Office of Communications should consider which customer classes should be target audiences for energy education. It should examine best practices from other states, including California, New York and those in New England, in developing the campaign design. It should also address whether it would be appropriate to retain the services of a third party to design and manage the campaign. EDCs should participate in these deliberations as part of the development of their individual consumer education filings.

Additionally, the Office of Communications should incorporate any findings made by the Commission regarding demand side response (“DSR”), energy efficiency, or conservation in its statewide education programs. The DSR Working Group will be completing its current investigation in the near future and providing policy recommendations to the Commission. These recommendations will include methods for educating consumers about the benefits of DSR, energy efficiency, and conservation.

Finally, the Office of Communications will provide an annual report to the Commission that reviews program implementation, the costs incurred, and addresses the need for additional program funding, if any, beyond the initial allocation of $5 million.
B. Energy Conservation and Reduction of Peak Demand

1. Comments to the Tentative Order

Relatively few comments were provided to this section of the Tentative Order, as parties understand that these issues are currently being addressed in a separate proceeding. PECO and Constellation both expressed support for the pending investigation. PennFuture and the ECA offered specific comments regarding the energy conservation and demand response policies that should be adopted by the Commission.

2. Findings

During the early phases of this proceeding, the Commission received comments from multiple parties recommending consideration of initiatives in the areas of energy efficiency, conservation, and DSR. The Commission agreed with these recommendations, and initiated a separate proceeding to study these issues more closely. Investigation of Conservation, Energy Efficiency Activities, and Demand Side Response by Energy Utilities and Ratemaking Mechanisms to Promote Such Efforts, Docket No. M-00061984 (Order entered October 11, 2006). Pursuant to this order, the Director of Operations convened the DSR Working Group on November 16, 2006, to review the subjects of energy efficiency, DSR, advanced metering and revenue decoupling mechanisms.

The Commission hosted a panel of experts on these issues at a session on January 19, 2007. The Commission reviewed a number of studies on the benefits of DSR, energy efficiency, and conservation, including one by the Brattle Group for PJM Interconnection, LLC (“PJM”) and the Mid-Atlantic Distributed Resources Initiative on January 29, 2007. The DSR Working Group will be delivering a report to the Commission with findings and policy recommendations in the near future. Consumer
education initiatives developed as a consequence of this investigation will be coordinated
with any EDC or statewide campaigns approved by the Commission.

C. Alternatives to Abrupt Price Increases

1. Comments to the Tentative Order

Parties who commented on this section of the Tentative Order concurred with the
Commission’s proposed finding that a well designed default service rules are key element
of any efforts to mitigate price increases. There was also general support for the concept
that the Commission should be open to reasonable procurement strategies implemented in
advance of the expiration of rate caps. There was less agreement on the concept of
allowing ratepayers to prepay or defer some portion of a significant rate increase.

2. Findings

Prior to the issuance of the Tentative Order, the Commission solicited comments
on strategies to avoid large, abrupt increases in retail rates of the kind seen in
Pennsylvania and neighboring states as rate caps have expired. The Commission raised
the idea of either phasing in rate increases prior to the expiration of rate caps, or deferring
some portion of the rate increase to later years. Comments were offered both for and
against these types of options, but most parties oppose lifting generation rate caps at this
time. The Commission has also been asked to rule on several strategies for mitigating
price increases, as discussed in the following section.
a. Rate proceedings with price mitigation elements

The Metropolitan Edison Company and the Pennsylvania Electric Company sought an exception to their generation rate caps in petitions filed with the Commission on April 10, 2006. These companies asserted that permitting a generation rate increase now would mitigate the impact of a large, abrupt increase at the end of the transition period. This proposal was objected to by intervening parties as a violation of the rate cap provisions of the Public Utility Code and these companies’ restructuring settlements. The Commission’s Office of Administrative Law Judge concluded that an exception to the generation rate cap was not warranted in a Recommended Decision issued on October 31, 2006. The Commission affirmed this finding in an order issued at the Public Meeting of January 11, 2007. *Pennsylvania Public Utility Commission, et al. v. Metropolitan Edison Company; Pennsylvania Public Utility Commission, et al. v. Pennsylvania Electric Company*, Docket No. R-00061366, et al. and R-00061367, et al. (Orders entered January 11, 2007). In comments filed in response to the Tentative Order, the OCA reiterated its opposition to granting exceptions to generation caps as a component of any price mitigation policy.

Another strategy for mitigating price increases was proposed by PPL in its Competitive Bridge Plan filed with the Commission on August 2, 2006. While PPL’s generation rate cap will not expire until the end of 2009, it proposed to implement a three year program starting in 2007 to procure the necessary supply to meet its provider of last resort (“POLR”) obligations in 2010. It would obtain POLR supply for 2010 on the competitive market at prevailing market prices through 6 individual procurements from 2007 through 2009. Contracts would be laddered to mitigate price volatility. A Recommended Decision was issued on February 21, 2007, that approved a revised version of the plan agreed to by multiple parties. The Commission adopted a motion at the Public Meeting of May 10, 2007, that partially adopted, and partially revised, the
The above discussion serves to illustrate the kinds of proposals that may be filed with the Commission between now and the expiration of the remaining rate caps. The Commission reserves judgment on the types of ideas discussed above, and will continue to address proposals on a case by case basis.

b. Default service regulatory framework

Many of those filing comments on price mitigation believe this issue can best be addressed through appropriate default service regulations. In comments filed prior to the issuance of a Tentative Order, there was general consensus that the Commission should promulgate rules as soon as reasonably possible that clearly define the obligations of EDCs, acceptable procurement strategies, and mechanisms for cost-recovery. Many parties, like the OCA, OSBA, DEP, and most EDCs, encouraged the utilization of certain procurement practices to minimize price volatility. Such methods include long term contracts and contract laddering. Other parties, such as Strategic Energy Limited and Direct Energy Services, focused more on the link between market prices and default service rates. They suggested greater use of short term pricing, including hourly priced service for large customers, and policies that will facilitate the participation of EGSs in Pennsylvania’s retail market.

50 The Commission issued proposed POLR regulations in late 2004. Rulemaking Re Electric Distribution Companies’ Obligation to Serve Retail Customers At the Conclusion of the Transition Period Pursuant to 66 Pa.C.S. § 2807(e)(2), Docket No, L-00040169 (Order entered December 16, 2004). The public comment period was extended to April 2006 to address compliance with the Alternative Energy Portfolio Standards Act of 2004, 73 P.S. § 1648.1, et seq. A final form version of this regulation must be delivered to the Independent Regulatory Review Commission by April 7, 2008, or it will be deemed withdrawn.
The Commission agrees that the completion of the default service rulemaking process is a necessary element of any price mitigation strategy. The Commission issued an advance notice of final rulemaking and proposed policy statement on default service at the Public Meeting of February 8, 2007. Rulemaking Re Electric Distribution Companies’ Obligation to Serve Retail Customers at the Conclusion of the Transition Period Pursuant To 66 Pa.C.S. § 2807(e)(2), Docket No. L-00040169 (Advance notice of final rulemaking order entered February 9, 2007); Default Service and Retail Electric Markets, Docket No. M-00072009 (Proposed Policy Statement Order entered February 9, 2007). The Commission approved a final form default service regulation and policy statement at the Public Meeting of May 10, 2007.

Both the OCA and RESA commented on the prepayment and deferral options for retail customers. Both agreed that such programs are worthy of consideration, but that participation should be voluntary. RESA only supported a prepayment option, observing that customers ultimately pay more with deferral options due to interest and carrying charges. These and other issues raised by U.S. Steel, Comperio and others regarding the proper default service design will be considered in the context of these proceedings.

D. Assistance for Low Income Customers

1. Comments to the Tentative Order

Some parties, such as the ECA, PennFuture, OCA, the PULP, recommended expanding access and funding for low income customer assistance programs. The PULP also recommended that the Commission continue to work to reduce the level of customer terminations.51 Others offered support for general principles. For example, RESA asked

51 The Commission is revising its regulations on residential utility service standards, including termination rules, as required by the recently adopted Chapter 14 of the Public Utility Code, Responsible Utility Customer Protection. An advance notice of proposed rulemaking was issued on November 30, 2006. Rulemaking to Amend the Provisions of 52 Pa. Code, Chapter 56 to Comply with the Provisions of 66 Pa.C.S., Chapter 14; General Review of
the Commission to ensure that electric generation supplier customers have full access to programs operated and funded by EDCs.

2. Findings

A review of programs for low income customers is a necessary component of this investigation. These ratepayers have historically received financial assistance from two sources: ratepayer funded customer assistance programs (“CAPs”) and the federal government’s Low Income Heating Assistance Program (“LIHEAP”). The Commission also mandates an energy conservation program for low income customers, the Low Income Usage Reduction Program (“LIURP”).\(^52\) The Commission has already taken some steps to increase CAP program availability, described below, and this tentative order will identify a new approach to obtain more LIHEAP funding.

a. Customer Assistance Programs

Over the past several years the Commission has undertaken a lengthy review of CAP program funding and cost-recovery. *Customer Assistance Programs: Funding Levels and Cost Recovery Mechanisms*, Docket No. M-00051923 (Order entered December 15, 2005). This investigation was initiated to develop standards for determining whether CAP programs were appropriately funded and how programs costs should be recovered. While the Commission has issued a policy statement on the design of CAP programs, it has not adopted regulations on funding levels and cost-recovery.\(^53\) Historically, these issues were addressed on a case by case basis. The Commission solicited comments on these issues from the public regarding the adoption of uniform standards and related issues.

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\(^{52}\) 52 Pa. Code § 58.1, et seq.

\(^{53}\) 52 Pa. Code § 69.261, et seq.
After completing its review of comments, the Commission issued an order that substantially revised its regulation of CAP programs. The Commission held that enrollment ceilings on CAP programs should be eliminated, that EDCs were authorized to use a surcharge to recover CAP costs, that cost-recovery would be limited to residential customers, and that the tariff filing process would be used to simultaneously address cost-recovery and program design elements. Customer Assistance Programs: Funding Levels and Cost Recovery Mechanisms, Docket No. M-00051923 (Final Investigatory Order entered December 18, 2006). The Commission will initiate a rulemaking process to modify its CAP policy statement and regulations consistent with this order.

Some issues raised in comments to the Tentative Order could be addressed in this rulemaking proceeding. For example, the ECA has recommended revising the definition of low income customers to include those at 200% of the Federal poverty income guidelines. The ECA and other parties with specific recommendations regarding CAP policies and regulations are therefore encouraged to participate in this proceeding.

b. LIHEAP

According to US Census Data, there are approximately 924,000 Pennsylvania households whose incomes are below 150 percent of the Federal Poverty Guidelines. In 2005, the Department of Public Welfare (“DPW”) provided an average LIHEAP benefit of $236 to 385,000 households, which represents approximately 41 percent of the eligible population. In 2005, the average annual energy bill was $2,224. Almost 60 percent of LIHEAP recipients had incomes below $11,000. The average LIHEAP benefit of $236 covered 8% of a typical household’s energy bill. A typical LIHEAP household has an energy burden of 19% compared with an energy burden of 4% for a household with an
average income of $54,000. This data is illustrated in more detail in a table at the end of this section.

In 2005-2006, the Commonwealth received a basic federal appropriation of $135 million, an energy contingency grant of $56 million, and a state supplement of $19.3 million. With the energy grant and the state supplement the total LIHEAP funding for 2005-2006 was $210 million. For 2006-2007, the Commonwealth will receive a $120 million federal appropriation. Based on a review of the information available to us, we find that the current level of LIHEAP funding is not sufficient to enable many recipients to maintain their utility service. Moreover, due to the current funding levels, LIHEAP benefits are not available to every customer who requests assistance. Additionally, reductions in LIHEAP funding increase the cost of CAP programs, costs that will be recovered from ratepayers.

The Commission has testified about the importance of LIHEAP, its relationship to utility-sponsored universal service programs, and the inadequacy of the LIHEAP appropriation. However, the Commission has not requested that the Pennsylvania General Assembly provide a state supplement to these funds. Traditionally, the Commission’s representative on the LIHEAP Advisory Committee (“LAC”) has abstained from voting on recommendations that requested state funding to supplement LIHEAP. The LAC provides recommendations on funding levels to the Secretary of DPW, which are then forwarded to the Governor’s Office.

The Commission finds that the public interest would be served by becoming a stronger advocate for increased state funding of LIHEAP before both the Pennsylvania General Assembly and in the LAC. Therefore, the Bureau of Consumer Services will actively participate in LAC and vote on policy recommendations. With this change in policy, the Commission can now actively participate with DPW, OCA, the PULP and other concerned parties to secure state funding. By giving our technical support to the
development of recommendations, we can also enhance the effectiveness of efforts for additional funding. Actively working with the Universal Service Task Force and the LAC to develop recommendations will be an important first step of this process.

c. LIURP

Some participants in this proceeding suggested increasing LIURP funding. In comments to the Tentative Order, both PennFuture and the PULP recommended that additional funding be considered. The minimum LIURP funding requirements and the standards for revision have been set through Commission regulations. A utility may petition the Commission to approve a revised funding level, or the Commission may revise the funding level by order after a consideration of a number of factors, including the cost-effectiveness of program expansion.

Accordingly, this is not the appropriate proceeding to revise LIURP funding levels. Electric and gas utility LIURP funding is reviewed as part of the Commission’s triennial review of their universal service programs. Interested parties may intervene in these proceedings and offer evidence that would support an increase in funding.

Additionally, we find that the triennial review process is also the most appropriate forum for addressing the OCA’s request for greater support of Hardship Funds, and the ECA’s concerns regarding the effectiveness of LIURP programs. We welcome any evidence regarding or specific proposals for increasing the effectiveness of LIURP and Hardship Funds. These parties may all properly address these issues in the context of the CAP rulemaking we will be initiating.

54 52 Pa. Code § 58.4
55 52 Pa. Code §§ 54.74 and 62.4
However, the Commission will address specific requests for LIURP funding increases within the context of other proceedings. For example, the Commission recently approved a settlement of a distribution rate case filed by Duquesne Light Company that includes an expansion of LIURP funding. *Pa. Public Utility Commission v. Duquesne Light Company*, Docket No. R-00061346 (Order issued November 30, 2006). Pursuant to the terms of the settlement, funding will increase by $350,000 to about $1.5 million per year. This will permit enrollment in the program to increase from 1,750 to 2,250 customers.

<table>
<thead>
<tr>
<th>2005* Average Energy Burden in Pennsylvania</th>
<th></th>
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</thead>
<tbody>
<tr>
<td>TANF Annual Grant</td>
<td>Annual Minimum Wage Income</td>
</tr>
<tr>
<td>Annual Income</td>
<td>$4,836</td>
</tr>
<tr>
<td>Home Energy Bill</td>
<td>$2,224</td>
</tr>
<tr>
<td>LIHEAP Cash Grant</td>
<td>$398</td>
</tr>
<tr>
<td>Annual Energy Cost with LIHEAP assistance</td>
<td>$1,826</td>
</tr>
<tr>
<td>Energy Burden with LIHEAP</td>
<td>37.8%</td>
</tr>
<tr>
<td>Energy Burden without LIHEAP</td>
<td>46.0%</td>
</tr>
<tr>
<td>Monthly budget enrolled in CAP that is consistent with 52 Pa. Code § 69.262-267</td>
<td>$52 or 13% of household income</td>
</tr>
<tr>
<td>Monthly budget at 16% of household income</td>
<td></td>
</tr>
<tr>
<td>Income Corresponds to % of Poverty Guidelines</td>
<td>30%</td>
</tr>
</tbody>
</table>

56 “Total Assistance for Needy Families."
E. The Relationship between Wholesale Energy Markets and Retail Rates

1. Comments to the Tentative Order

Several parties filed comments in response to this section of the Tentative Order. These parties were supportive of the Commission’s involvement in proceedings at the Federal Energy Regulatory Commission (“FERC”) and the PJM Interconnection, LLC, and some recommended that the Commission take additional, specific steps to advance the development of effective retail and wholesale energy markets.

Comperio identified three items for Commission consideration. First, the Commission should become more involved at PJM by seeking member status and a seat on PJM’s Board of Managers. Second, the Commission should require all EDCs under its jurisdiction to join PJM, which it believes would facilitate customer choice and lead to more competitive pricing. Finally, the Commission should continue the process of developing uniform, statewide rules regarding billing, access to customer data, etc. to facilitate retail competition.

IECPA recommended that the Commission develop an action plan to improve the operation of PJM’s wholesale energy market. IECPA reiterated its criticism of locational marginal pricing (“LMP”), which it asserts improperly inflates market prices for low cost generation sources, inhibits long-term contracts, and fails to stimulate investment in needed infrastructure. IECPA also maintains that PJM is vulnerable to market power, and that PJM market participants are improperly gaming market rules for unbundled services, all to the detriment of retail customers.

IECPA revisits recommendations from comments submitted earlier in this proceeding. It recommends that the Commission facilitate the siting of low cost
generation, remove EDC tariff provisions that impede customer participation in DSR
programs, require EDCs to offer long-term contracts pursuant to their default service
obligation, investigate the viability of a public power authority, and encourage generators
to enter into long-term contracts at cost-plus pricing with Pennsylvania customers.
IECPA asserts that these measures are well within the Commission’s authority, and that
the Commission should address them in this proceeding.

2. Findings

a. The Commission will continue to represent Pennsylvania’s interests before the FERC.

The Commission agrees that aggressive representation of Pennsylvania’s interests
before the FERC is an important component of efforts to address electricity price issues.
The Commission will continue its policy of active participation at FERC, and will
intervene in relevant proceedings as opportunities arise. Recent proceedings in which the
Commission has participated include:

PJM Interconnection, LLC, ER06-456-000, ER06-456-001, ER06-456-002, et al.;
Consolidated proceeding to allocate costs of regional transmission upgrades.
PJM Interconnection, LLC, ER05-1410-000 and EL05-148-000; Proceeding on
PJM’s “Reliability Pricing Model.”
PJM Interconnection, LLC, ER06-826-000; Proceeding addressing independence
of PJM’s market monitoring unit.
PJM Interconnection, LLC, ER05-1181-000; Proceeding involving rates by which
PJM will recover operational expenses.
Midwest Independent Transmission System Operator, Inc., etc., EL02-111; EL-03-
212, EL04-135, ER-05-6, etc.; Proceeding involving “Seams Elimination Cost
Adjustment.”
Wisconsin Public Service Corporation, et al. v. Midwest Independent
Transmission System Operator, Inc. and PJM Interconnection, LLC, EL06-97-
000; Proceeding to force PJM and the Midwest Independent Transmission System
Operator, Inc. ("MISO") to institute joint unit commitment and single system dispatch, necessary elements of a joint and common energy market. 

*Regulations for Filing Applications for Permits to Site Interstate Electric Transmission Corridors*, RM06-12-000; Rulemaking to implement transmission siting provisions of the Energy Policy Act of 2005 ("EPACT"). 

*Preventing Undue Discrimination and Preference in Transmission Services*, RM05-17-000 and RM05-25-000. Rulemaking to implement transmission related provisions of EPACT. 

*Promoting Transmission Investment Through Pricing Reforms*, RM06-4-000, Rulemaking to implement transmission related provisions of EPACT. 

*Duquesne Light Company*, ER-06-1549-000, EL06-109-000; Proceeding for cost recovery and incentive rates for Duquesne transmission facilities. 

*Order Convening Joint Boards Pursuant to Section 223 of the Federal Power Act*, AD05-13-000; Proceeding required by EPACT to investigate and provide recommendations regarding security constrained economic dispatch.

### b. The Commission will maintain an active role at PJM and MISO.

The Commission has been proactive in working with other state utility commissions to jointly address wholesale energy issues with PJM. Pennsylvania and the other PJM member states recognized that ratepayer interests would be better served if member states took a collaborative approach in working with PJM. Accordingly, on May 19, 2005, the Commission incorporated the Organization of PJM States, Inc. ("OPSI"). OPSI’s mission is to act as a liaison to PJM for the states and collect information, monitor markets and events, etc.\(^\text{57}\) On June 1, 2005, PJM and OPSI entered into a Memorandum of Understanding wherein they agreed that PJM and OPSI would meet at least annually, that PJM would provide OPSI information on a timely basis, and that the parties would share and consider proposals affecting reliability, safety, facility siting and electricity prices.

\(^{57}\) As an example of its active representation of Pennsylvania’s interests, the Commission, in its capacity as a member of OPSI, filed a complaint at the FERC on April 23, 2007, against PJM regarding the independence of PJM’s market monitoring unit. *Organization of PJM States, Inc., et al. v. PJM Interconnection, LLC*, Docket No. EL07-58.
A PJM tariff to fund OPSI was approved by FERC on December 20, 2005. *PJM Interconnection, LLC;* 113 FERC ¶61,292. OPSI has filed joint comments in proceedings at FERC, and maintains an ongoing dialogue with PJM on numerous issues. The Commission is also a member of the Organization of MISO States, as MISO’s control area includes the Penn Power service territory.

c. The Commission will address other jurisdictional issues in separate proceedings.

Both Comperio and Constellation support the development of uniform rules for retail choice and wholesale energy procurements. The Commission agrees that uniform, statewide rules on certain issues are in the public interest. The standardization of supplier master agreements and request for proposal documents will be addressed in a pending proceeding. The Commission has also proposed to establish a Retail Markets Working Group that could address issues relating to billing, customer information access, etc., as component of its default service policy statement.

Certain issues identified by IECPA relating to DSR and default service are also properly within the scope of other proceedings. We agree with IECPA that EDCs should eliminate tariff provisions that improperly restrict the ability of customers to participate in DSR programs. As discussed earlier in this Final Order, there is a proceeding pending before the Commission regarding DSR. Commission staff has included this issue among those that were circulated to the DSR Working Group for comment. The DSR Working Group and Commission staff will be providing policy recommendations to the Commission on this and other topics in the near future. The issue of long-term contracts


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for default service customers lies within the scope of Commission’s default service rulemaking.

Not all the recommendations offered by Comperio and IECPA are clearly within the Commission’s power to implement. The Commission’s authority must derive from the express words of statute, or by necessary and strong implication therefrom. City of Philadelphia v. Philadelphia Electric Co., 473 A.2d 997 (Pa. 1984). The legislative grant of power to act in a particular case must be clear. Id. It is not clear that the Commission can become a full-fledged PJM member or join its board of managers, order EDCs to join PJM, pre-approve the siting of electric generation facilities, or order generators to enter into long-term contracts at cost plus pricing with Pennsylvania customers.

While the Commission does monitor PJM proceedings, and participate in stakeholder working groups, its role there is circumscribed by the PJM Operating Agreement, which is subject to FERC, and not Commission, approval. PJM membership is limited to generation owners, electric distributors, transmission owners, other suppliers, and end-use customers. State utility commissions may nominate representatives to serve as ex officio non-voting members of standing committees. The Commission has declined to formalize its role to that extent, but remains open to doing so should it deem it to be in the public interest.

Additionally, it is not clear that the Commission has the authority to order an EDC to join PJM, as suggested by Comperio. While the Commission has approved RTO membership as a term of proposed settlement agreements, it has never directed a particular EDC to join an RTO. The only Pennsylvania EDCs that do not belong to PJM are the Pennsylvania Power Company and Pike County Light & Power (“Pike”). The costs and benefits of Pike’s membership in PJM were studied in an investigation conducted last year. Initiation of a Fact Finding Investigation of the Competitive Market Conditions re: Pike County Light & Power Company, Docket No. P-00052168 (Order
entered February 14, 2006). The information collected did not conclusively demonstrate that PJM membership was clearly in the public interest. This issue is also the subject of litigation in a separate pending proceeding. *County of Pike v. Pike County Light & Power Company*, Docket Nos. C-200065942, *et al*.

IECPA makes several other recommendations that are not clearly within Commission’s authority. As mentioned earlier, IECPA has recommended that the Commission, in concert with other agencies, identify and pre-approve the siting of generation, seek bids for the construction of new generation, and condition regulatory approvals for the siting and construction of new generation on the execution of cost plus, long-term contracts with customers, etc. IECPA identifies no precedent or statutory authority that would empower the Commission to engage in such activities.\(^5^9\) In fact, Section 2806(a) of the Public Utility Code, 66 Pa.C.S. § 2806(a), provides that “the generation of electricity shall no longer be regulated as a public service or function,” except in the context of default service. However, the Commission does stand ready to lend whatever technical assistance it can to those agencies responsible for the permitting and approval of new generation construction in Pennsylvania.

We observe that IECPA’s recommendations are apparently being addressed in the context of Governor Rendell’s Energy Independence Strategy (“EIS”). Pursuant to the EIS, the Pennsylvania Energy Development Authority (“PEDA”) would be given the power to purchase, redistribute and sell electricity, natural gas, and other energy commodities to retail customers. PEDA would also be able to enter into energy agreements with other parties to provide funds for working capital, equipment acquisition, construction and site preparation. This statutory authority would seem to

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\(^{5^9}\) Public utilities may exercise eminent domain powers to acquire land for various purposes, including the generation of electricity, pursuant to 15 Pa. C.S. § 1511(a). The Commission must separately determine that the use of this eminent domain power, in the context of erecting or running wires or poles associated with electric or telecommunication service, is necessary for the accommodation, safety and convenience of the public. 15 Pa.C.S. § 1511(c). However, these provisions do not confer any power on the Commission to “pre-approve” the siting of electric generation facilities by utilities, much less projects proposed by non-regulated merchant generation companies.
encompass the construction of new generation and sale of electricity to large customers at cost plus rates. Legislation has been introduced to implement this component of the EIS.\textsuperscript{60} Thus, it appears that the viability of a Pennsylvania power authority and economic development rates for industrial customers will be addressed by the Pennsylvania General Assembly in their consideration of the EIS.

CONCLUSION

The Commission appreciates the serious challenge that rising wholesale energy prices poses to Pennsylvania’s economy and the welfare of its citizens. Addressing this challenge in a constructive manner will require the cooperation of all stakeholders in Pennsylvania’s energy sectors. We find that this proceeding has been productive in identifying policy tools available to the Commission, and thank those parties who filed comments and participated in the June 22 hearing. We encourage stakeholders to continue their involvement in current and future proceedings resulting from this investigation; \textbf{THEREFORE:}

\textbf{IT IS ORDERED THAT:}

1. That a copy of this Final Order is served on all electric distribution companies, electric generation suppliers, the Office of Consumer Advocate, the Office of Small Business Advocate, and the Office of Trial Staff.

2. That the Office of Communications will convene a meeting of interested stakeholders within 60 days of the entry of this Final Order to develop a statewide consumer education program. The Office of Communications will provide an annual report to the Commission on the implementation of the program.

\textsuperscript{60} Senate Bill 661. Introduced on March 22, 2007, and referred to the Environmental Resources and Energy committee.
3. That all electric distribution companies prepare and file a consumer education plan by December 31, 2007.

4. That the Bureau of Consumer Services modifies its participation in the LIHEAP Advisory Council, consistent with this Final Order.

BY THE COMMISSION,

James J. McNulty,
Secretary

(SEAL)
ORDER ADOPTED: May 10, 2007
ORDER ENTERED: May 17, 2007