Biennial Report on the State of Electric Restructuring

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Revised April 2, 2007

BIENNIAL REPORT
TO THE OHIO GENERAL ASSEMBLY ON THE STATE OF ELECTRIC SERVICE RESTRUCTURING
BY
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL
REVISED MARCH, 2007

Pursuant to Section 4928.06 of the Ohio Revised Code, the Office of the Ohio Consumers' Counsel (OCC) hereby submits its report regarding the effectiveness of competition in the supply of competitive retail electric services in this state. The Office of the Ohio Consumers' Counsel is the state representative of Ohio's residential utility consumers.

Section 4928.06 of the Ohio Revised Code provides key factors to consider when making a determination of whether there is effective competition. These factors include the number and size of alternative providers; the extent to which service is available from those providers; the ability of alternative suppliers to make functionally equivalent or substitute services readily available at competitive prices, terms and conditions; and, other indicators of market power which may include market share, growth in market share, ease of entry and the affiliation of suppliers of service.

The simple answer to these questions is that there are 19 certified suppliers available,[1] few if any of which are providing service to residential customers.[2] These suppliers appear unable to make functionally equivalent or substitute services available at competitive prices, terms and conditions, largely because the regulatory construct has failed to create a level playing field since the dawning of deregulation. The incumbent utility companies continue to exercise market power due to regulatory decisions that have provided them with a competitive advantage.

Summary of Conclusions

It was envisioned when Senate Bill 3 passed that there would be significant marketing to individual customers, similar to what has transpired with customer choice in the natural gas industry. Unfortunately, what was envisioned never came to fruition largely due to the structure of the incumbent utility's Electric Transition Plans (ETP) which were later superseded by the equally problematic Rate Stabilization Plans (RSP). The bottom line is that in the six years subsequent to the passage of Senate Bill 3, competition has never had the chance it was entitled to under the law. As a result, due to lost opportunities in the competitive market, customers in some parts of the state are possibly paying higher electric rates than they otherwise should have, had the plans for competition been properly structured in accordance with the law.

There are many who look at the dearth of competitive options and argue that competition can never work. It can be deemed that such a conclusion is premature. The fact of the matter is that we do not know if competition can truly work because it has never been given a fair chance. The simple answer could be to correct the structure of competition, follow the intent of Senate Bill 3 and give competition a meaningful opportunity. The free market has worked in a number of industries to provide benefits to customers. However, as with other industries operating in a free market – the basis of the American economic system – the public only benefits if there is true competition.

From a consumer perspective, customers can be properly protected through attentive regulation or through competition in which market forces keep prices as low as possible. Hybrid plans that provide the incumbent utilities with the flexibility to navigate between regulation and deregulation as it suits their corporate interests do not serve the public. The hybrid plans embodied in the Rate Stabilization Plans approved by the Public Utilities Commission of Ohio (PUCO) shift risk to the customers and away from the utilities. Ohio has yet to embark on a true competitive path as outlined in Senate Bill 3 and until the state undertakes that task, we will not know if customers can benefit for sure. The key policy driver ought to be creating a paradigm that always puts the customer first by making energy available at affordable rates, stabilized at prices brought on by competition, and allowing the incumbent utilities the opportunity to earn a reasonable return on their regulated businesses. The consumers who pay the bills should come first.

The Rate Stabilization Plans (RSPs)

Section 4928.14 of the Revised Code requires the incumbent utilities to offer customers a market based standard service offer and a competitively bid option.[3] Instead of following this directive, the utilities filed and the PUCO approved, Rate Stabilization Plans with three goals in mind: 1) stabilize rates, 2) provide revenue stability for the utilities and 3) help foster competition.[4] The only goal that was actually achieved was the revenue stability for the utilities. Many customers have seen significant impacts on generation rates because of these plans and as noted above, competition is stagnant, thereby offering no relief from the utility rates. A closer look at each utility's rate plan and the Supreme Court of Ohio's rulings with respect to the Consumers' Counsel's appeals is discussed below.

FirstEnergy

Under Senate Bill 3, at the end of the Market Development Period, stranded costs associated with utility power plants are no longer recoverable.[5] In the FirstEnergy service territory, this amounted to approximately $2.9 billion, $1 billion of which was charged to residential customers.[6] Customers of FirstEnergy who have been strapped with historically high rates should have seen a break in their costs. These stranded cost charges, after all, ranged from $15 to $20 per month for an annual cost of $180 to $240 per year. [7] Instead, FirstEnergy successfully argued that it needed to continue collecting these amounts as a "Rate Stabilization Charge" or "RSC" which has no basis in law. Ostensibly, this is the charge all customers must pay FirstEnergy for its risk in being the supplier of last resort.[8]

One would expect FirstEnergy's risk to be comparable to that of AEP, yet while FirstEnergy's average charge is $.0208 per kwh[9], AEP's average charge is $.0012.[10] No analysis was ever provided to quantify the risk of this PUCO-approved charge.[11] Furthermore, under the Rate Stabilization Plan, artificial caps were placed on the amount of FirstEnergy charges that could be avoidable in the event a customer switches. These caps or "shopping credits" (the price a marketer must beat for a customer to save money) actually were lower in some instances than the shopping credits allowed under the original Electric Transition Plans despite the fact that market prices have been going up.[12] In other words, under the law, a customer who switches should be required to pay the incumbent utility the price of distribution, transmission and any remaining regulatory transition charge with the generation price being entirely avoidable. Instead, under the Rate Stabilization Plan, the switching customer pays much more. Thus, the opportunity for a customer to save by shopping for another supplier becomes extremely difficult, if not impossible. This has been an obstacle to competitive suppliers that are able to do business in other states, but have been unable to economically justify trying to serve Ohio customers with electricity.

Similarly, the OCC appealed the PUCO's decision, which the Supreme Court of Ohio reversed in part and affirmed in part. The Court held that the PUCO had overstepped its jurisdiction by approving a plan that did not present to customers a reasonably available alternative. The case has been remanded back to the PUCO.

FirstEnergy's Rate Stabilization Plan was approved with a promise that rates were not going up. The fact of the matter is that the customers in northern Ohio who were paying significantly more than their counterparts in the south should have seen a rate break. This did not occur. In addition, while FirstEnergy stated that it would not raise rates to recovery fuel costs, it made such a filing only months later. Adhering to its mantra about not raising rates, FirstEnergy reached a settlement approved by the PUCO that allowed FirstEnergy to defer fuel costs estimated at over $90 million,[13] along with another $450 million in deferred distribution costs[14] that will be saddled on all customers to pay as a non-bypassable or unavoidable charge over the next 25 years,[15] beginning as early as January 2009.[16] Even if competition develops and customers choose an alternative supplier, these fuel costs will still be charged to customers.

American Electric Power Company (AEP)

The Rate Stabilization Plan approved for AEP provided AEP's two utility companies with the flexibility to increase rates over the three year period of 2006 through 2008 by up to $1.17 billion,[17] with $527 million[18] of that amount related to fixed generation rate increases during the RSP period. (The 2006 fixed generation rate increases and the new deferrals was $160 million). The remaining $643 million could potentially be used for additional generation increases during the RSP period associated with environmental costs, taxes, security, and generation-related regulatory expenses.[19] The OCC appealed the PUCO's order approving this plan on the grounds it was unlawful. The Court concurred, vacated the PUCO's decision and remanded the case to the PUCO for further proceedings.

In that decision, the PUCO, on its own initiative, encouraged AEP to move forward with a plan to construct an Integrated Gasification Combined Cycle (IGCC) plant.[20] AEP subsequently filed a three-phase plan to pre-recover and recover [21] the costs of the IGCC estimated at the time of filing at $1.3 billion.[22] This plant is being built to provide power to a distribution company, which is completely contradictory to the statutory requirements of corporate separation, meaning the distribution companies can no longer own generation. By guaranteeing collection of costs for a power plant, the PUCO has given AEP a competitive advantage over other power plant producers, thereby injuring the competitive market. From a customer standpoint, this provides no assurance that the AEP plant is the least cost option for power since there was no competitive bid. Moreover, there is no cap on the price of the plant, which could potentially lead customers to pay the type of unlimited amount for construction that deregulation was designed to avoid. Furthermore, requiring customers to pre-pay as opposed to paying when the plant is "used and useful" as required under traditional regulation, results in the customers taking the risk which properly resides with the utility company. While OCC supports IGCC, it cannot support the unlawful and unfair recovery mechanism. OCC along with the industrial customers have appealed that decision to the Supreme Court of Ohio.

Duke Energy (Duke)

In Duke's Rate Stabilization Plan case, the PUCO approved a stipulation that allowed Duke to create four new riders[23] through which Duke collected from residential customers over $100 million in additional revenue [24] in the first year. The riders consisted of an Annually Adjusted Component, a System Reliability Tracker, a Fuel and Purchased Power Rider and an Infrastructure Maintenance Fund. For residential customers two of these charges (SRT and IMF)[25] are non-bypassable, meaning that even if a customer switches to another supplier, that customer still has to pay these charges. This defeats one of the purposes of the Rate Stabilization Plan which ostensibly was to promote competition. If customers have to pay for these charges regardless of the supplier, then the amount of costs they can avoid from switching are minimized and could affect their ability to find a competitive supplier.

The OCC appealed the PUCO's decision and the Court ruled that the PUCO erred in approving these charges on rehearing without evidentiary support or justification. The Court also held that the PUCO abused its discretion in failing to require Duke to produce the side agreements OCC had requested during the case. The Court reasoned that the existence of concessions and inducements would be relevant in the context of open multi-party settlement discussions to determine if those negotiations were fairly conducted since one or more parties may have gained an unfair advantage in the bargaining process.

Dayton Power and Light Company (DP&L)

Under the Electric Transition Plan, DP&L's Market Development Period (MDP) was slated to terminate at the end of 2003.[26] Because there was no competition, a settlement was entered into that extended the MDP through 2005 and set up a rate stabilization period for 2006 through 2008,[27] creating the first Rate Stabilization Plan case. Following the approval of rate plans that were more lucrative for other electric utilities, DP&L decided that the comparatively modest agreement it had signed was inadequate. DP&L requested further customer rate increases. Ignoring the initial settlement reached in the matter, the PUCO approved a net increase of $185 million for this small company.[28] The OCC has appealed this decision to the Supreme Court of Ohio and is awaiting a ruling.[29]

Summary on Retail Competition

Since the last biennial report, regrettably, competition has declined. Individual shopping by residential customers is not occurring. This is due in large part to the structure of the Rate Stabilization Plans which produce artificial shopping credits that are below the market price and are below the electric utilities' true generation costs. With this reality, competitive retail electric suppliers are reluctant to commit their companies' resources in a state where they are hindered from offering a competitive product. In order for the free market to work, the full generation prices of the utility company needs to be avoidable, as was intended by Senate Bill 3, and which has yet to occur.

Due to a combination of factors, aggregation – which was the jewel of deregulation – has also dissipated. The Northeast Ohio Public Energy Council (NOPEC) at the time of the last biennial report had a vibrant aggregation program producing savings [30] to over 450,000 customers[31] through a contract with a competitive supplier. The supplier later defaulted. [32]

Wholesale Competition

The failure of competition in Ohio is due largely to structural infirmities at both the retail and wholesale level. The interconnectivity between the wholesale and retail market structures cannot be ignored. The problems with the wholesale market are manifold. In order to facilitate the reliable flow of bulk power, Regional Transmission Organizations (RTOs) were created to operate on an interstate basis.

Unfortunately, Ohio is divided with two RTOs – PJM to which AEP and DP&L belong[33] and Midwest Independent System Operator (MISO) to which FirstEnergy and Duke belong. [34] This has created "seams issues"[35] that have impeded the flow of energy across the state. Each of the RTOs has created different structures, each with its costs that are passed on to customers. The list of issues that are affecting the development of the market is long and those issues need to be addressed. The OCC has made a commitment to work with other Ohio stakeholders as well as consumer advocates from other states to improve the wholesale market. This requires participation in meetings and negotiations at MISO and PJM as well as participation in proceedings before the Federal Energy Regulatory Commission.

Next Steps

It is clear that we need to develop a plan for the electric industry post-2008. Continuation of the Rate Stabilization Plans may not be in the best interest of the public given the lack of scrutiny by the PUCO and the Supreme Court of Ohio decisions. Moreover, the failure to have a roadmap creates uncertainty that hampers economic development. Consumers, whether they are large businesses or residential customers, need to be able to budget for utility costs. The band-aid of individual utility plans keeps us guessing regarding what the power needs are for this state and prevents us from addressing important energy issues in a holistic manner.

The increasing public concern over energy has been demonstrated through numerous articles in the media. There is now a public debate regarding our energy future and it includes concerns such as reliability, affordability, environmental impacts, energy efficiency and independence, and national security. State legislators and regulators across the nation are putting together plans that are designed to help provide solutions. Ohio needs to do so as well.

Deregulation should have and could have worked had Ohio implemented it as intended by the General Assembly. There are many examples of lost opportunities where customers were denied the abilities they should have had under deregulation to save money. For example, had the first auction price for FirstEnergy been accepted back in 2004, customers today could be saving money for generation over the current amount for generation being paid under the Rate Stabilization Plan and Rate Certainty Plan. Additionally, the auction price was a fixed price, whereas the FirstEnergy Rate Stabilization Plan allowed for generation increases (which have occurred in the form of deferrals pursuant to the Rate Certainty Plan). Given where we are, however, it is now necessary to take a step back and focus on wholesale bidding for customers. In order to serve customers who do not switch, there could be a competitive bid in which suppliers can provide power based on slices – or tranches – of the system.

However, the bid should not be conducted as was done with FirstEnergy, where all the load is bid at once into the short-term market. Rather, Ohio could use a portfolio approach of long and short-term bids in order to create a diversified portfolio of options which also creates a hedge against any one option which may be too costly. Through this mechanism, Ohio can assure customers are receiving electricity at a competitive price and that clean coal plants are built in this state, while at the same time fostering alternative energy and energy efficiency.

While competition has not been a success as anticipated, it still could be successful if structured correctly. Steps should be taken to correct the mistakes and to carefully steer the state back on course. The OCC looks forward to working with the legislature and the Governor's office as well as other stakeholders to craft a policy that creates a win-win for Ohio's consumers and the future of this state.

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[1] Source: PUCO Website - "Certification Report" dated 17-Oct-96
There are a total of 20 Marketers and/or Brokers certified.

[2] Source: PUCO Website - "Summary of Switch Rates from EDU's to CRES Provides in Terms of Customers For the Month Ending December 31, 2006" there were 265,953 residential shopping customers out of 4,1271,103 total residential customers - - or 6% of residential customers that were shopping customers

[3] Source: R.C. 4928.14

"R.C. 4928.14. Market-based standard service offer; competitive bidding process; failure to provide service.
(A) After its market development period, an electric distribution utility in this state shall provide consumers, on a comparable and nondiscriminatory basis within its certified territory, a market-based standard service offer of all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service. Such offer shall be filed with the public utilities commission under section 4909.18 of the Revised Code.
(B) After that market development period, each electric distribution utility also shall offer customers within its certified territory an option to purchase competitive retail electric service the price of which is determined through a competitive bidding process. Prior to January 1, 2004, the commission shall adopt rules concerning the conduct of the competitive bidding process, including the information requirements necessary for customers to choose this option and the requirements to evaluate qualified bidders. The commission may require that the competitive bidding process be reviewed by an independent third party. No generation supplier shall be prohibited from participating in the bidding process, provided that any winning bidder shall be considered a certified supplier for purposes of obligations to customers. At the election of the electric distribution utility, and approval of the commission, the competitive bidding option under this division may be used as the market-based standard offer required by division (A) of this section. The commission may determine at any time that a competitive bidding process is not required, if other means to accomplish generally the same option for customers is readily available in the market and a reasonable means for customer participation is developed."

[4] Sources: PUCO Orders in FE 03-1461-EL-UNC and CG&E 03-93-EL-ATA

"We encourage FirstEnergy to consider and develop plans for 2005 and beyond, which balance three objectives: rate certainty, financial stability for the electric distribution utilities and further competitive market development. First Energy, Case No. 03-1461-EL-UNC, Entry at 4-5 (September 23, 2003);

"The Commission has established three goals that may be met by an RSP, where CRES markets have not fully developed by the end of utility's MDP: (1) rate certainty for consumers, (2) financial stability for the utility, and (3) the further development of competitive markets. Cincinnati Gas & Electric, Case No. 03-93-EL-ATA, Order at 15 (September 29, 2004).

[5] Source: R.C. 4928.40

Notes: The GTC was to have ended after the MDP. R.C.4928.40 (A) provides that "the transition charge" could be collected until the end of the MDP, no later than December 31, 2005. However, regulatory assets collection could end no later than December 31, 2010. Therefore, there was a distinction between two types of transition charges - (1) GTC (Generation Transition Charge) ending no later than 12/31/05 and (2) RTC (Regulatory Transition Charge), ending no later than 12/31/10. Transition revenue was to recover transition costs, those prudent costs related to electric generation that are "unrecoverable in a competitive market" and that the utility would have otherwise been "entitled an opportunity" to recover. Transition costs could have included above-market generation costs, regulatory assets and employee assistance costs.

"R.C. 4928.40 (A) Upon determining under section 4928.39 of the Revised Code the allowable transition costs of an electric utility authorized for collection as transition revenues under sections 4928.31 to 4928.40 of the Revised Code, the public utilities commission, by order under section 4928.33 of the Revised Code, shall establish the transition charge for each customer class of the electric utility and, to the extent possible, each rate schedule within each such customer class, with all such transition charges being collected as provided in division (A)(1)(b) of section 4928.37 of the Revised Code during a market development period for the utility, ending on such date as the commission shall reasonably prescribe. The market development period shall end on December 31, 2005, unless otherwise authorized under division (B) (2) of this section. However, the commission may set the utility's recovery of the revenue requirements associated with regulatory assets, as established pursuant to section 4928.39 of the Revised Code, to end not later than December 31, 2010. The commission shall not permit the creation or amortization of additional regulatory assets without notice and an opportunity to be heard through an evidentiary hearing and shall not increase the charge recovering such revenue requirements associated with regulatory assets."

[6] Source: OCC Witness Pultz Schedule FRP-2 in Case No. 03-2144-EL-ATA

Mr. Pultz estimated "Rate Stabilization Charge Revenue" to be collected from all customers for the years 2006 through 2008 was $2.918 billion, with the residential share as $1.027 billion. These estimates were based on the average GTC rates (in 2006 these became RSC) per Staff testimony applied to annual sales per FE's 2003 LTFR.

Sources: OCC Witness Pultz Schedule FRP-2 in Case No. 03-2144-EL-ATA
OCC Fact Sheet "What you should know about electric rates in 2006, FirstEnergy Customers" updated November 2006 and OCC website "First Energy rate plan will keep customers' rates high" September 2005

Stranded cost charges = GTC charges during MDP: The $180 to $240 annual cost to residential customers is the range for CEI ($180), OE ($216) and TE ($240) using the average GTC rates times 850 Kwh per month, times 12 months.

[8] Source: Order at 22, FirstEnergy Case No. 03-2144-EL-ATA (6/9/04)

"The RSP was represented by FirstEnergy to be its determination of the parameters within which it is willing to assume the risks of continuing to supply POLR service at a fixed, market-based generation price, using its generation assets, in the period following the MDP, while still maintaining its financial integrity. (FirstEnergy Exh. 1 at 9). The RSC is the charge intended to compensate FirstEnergy for the cost of reserving and supplying that generation."

Source: OCC Witness Pultz Schedule FRP-2 in Case No. 03-2144-EL-ATA

Average GTC/RSC Residential rates: OE ($.02102 kwh), CEI ($.01827 kwh), TE ($.02325 kwh)

[10] Source: OP Provider of Last Resort Charge, Tariff Sheet 69-1, effective 1/1/06 and CSP Provided of Last Resort Charge, Tariff Sheet

Ohio Power Residential POLR Charge per kWh = $.0016241
Columbus Southern Power Residential POLR Charge per kWh = $.0008192

[11] Source: Order at 23, FirstEnergy Case No. 03-2144-EL-ATA (6/9/04)
Order at 27 and 29, CSP and OP Case No. 04-169-EL-UNC

For First Energy, there was no analysis to quantify the risk that the RSC is to recover: "FirstEnergy was clear in its assertion that the proposed RSC was not cost based or the product of extensive studies or analysis as to the appropriate rate for assuming the risk of rate certainty. Company CEO Alexander succinctly stated that the source for the RSC was his judgment based on years in the industry.

However, for the AEP companies, the POLR charge came as a result of the PUCO denying AEP deferral of certain costs and instead approving those costs for collection through a POLR charge: "We believe the proposed RTO administrative charge amounts for collection during the rate stabilization period constitute reasonable and not excessive compensation to AEP for part of the cost of fulfilling its POLR responsibilities and, accordingly, approve the collection of these amounts as part of POLR charge. This POLR charge will be established a part of a separate unavoidable rider that is applicable to all distribution customers." (At 29 - The PUCO also allowed recovery through the POLR charge of "AEP's expenditures for CWIP and in-service plant carrying charges" during the MDP).

[12] Source: OCC 2005 Biennial Report on the State of Electric Restructuring at 8 which cites the Initial Brief of NOPEC at 20 (March 17, 2004) in FirstEnergy Case No. 03-2144-EL-ATA.

"NOPEC argued on brief: "These shopping credit levels * * * are below the shopping credit levels in effect in 2003, and substantially below those currently in effect in 2004. The shopping credit levels * * * will eliminate competition."

[13] Source: 1/4/06 Order, 9/9/05 Stipulation, FirstEnergy Case No. 05-1125-EL-ATA ("FE RCP")

In the 9/9/05 Stipulation at 3, FirstEnergy indicates that it intended to seek fuel cost recovery during 2006 - 2008 totaling $345 million ($93, $113 and $139 annually). The PUCO Order at 7 indicates the partial recovery of fuel costs under the Stipulation is "$75 million in 2006 rates, $77 million in 2007 and $79 million in 2008" (a total of $231 million), and that "any fuel increase over those stated amounts will be capitalized as a regulatory asset for each of the Companies that will be included in the next distribution rate case." Therefore, the amount estimated deferrals is unknown. However, since FE said they intended to file for $345 million and agreed to recover $231 million, an estimate of the deferrals would be $114 million (i.e. 345-231=114))

[14] Source: 1/4/06 Order at 8, FE RCP Case No. 05-1125-EL-ATA

"The revised stipulation makes provision for capitalization and deferral of up to $150 million in distribution expenses in each of three years, 2006 through 2008."

[15] 9/9/05 Stipulation at 11, FE RCP Case No. 05-1125-EL-ATA

Distribution Deferrals and Fuel Deferrals "shall be recovered over a 25 year period as regulatory assets in rate base as part of the next distribution rate case..."

[16] 9/9/05 Stipulation at 6, FE RCP Case No. 05-1125-EL-ATA

". . . no increase in base distribution rates may be effective until on or after January 1, 2009 as to Ohio Edison and Toledo Edison, and May 1, 2009 as to CEI."

[17] Source: Order, CSP & OP Case No. 04-169-EL-UNC (1/26/05) ("AEP RSP").

$1.17 billion is the total potential revenue increases for both companies over 2006 through 2008: Order at 10, "AEP provided estimated revenue amounts expected from the fixed generation rate increases and the new deferrals to be recovered through during the RSP (AEP Exh. 3 at 10). " (A table at page 10 shows this to be over 2006 - 2008, $222 million for CSP and $535 million, for a total of $757 million.) "If the potential four percent generation increase were also added to the calculation, AEP acknowledges that the total estimated revenue amount combined for both companies becomes $1.17 billion."

[18] Source: Order at 16, AEP RSP Case No. 04-169-EL-UNC (1/26/05)

$527 million was AEP's estimated revenue related to the fixed generation rate increases of 3% (CSP) and 7% (OP) over the period 2006 - 2008. (AEP Witness Nelson testimony at 10 (AEP Exh.3, at 10) and Order at 16.)

AEP's estimated annual revenue increase for 2006 for "the fixed generation rate increases and the new deferrals" was $160 million ($48 CSP, $112 OP) per AEP Witness Nelson's testimony at 10.

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[19] Source: Order at 20, AEP RSP Case No. 04-169-EL-UNC (1/26/05)

AEP can seek additional generation rate increases for:
"(a) increased expenditures incurred through an affiliate pooling arrangement for complying with changes in laws/rules/regulations related to environmental requirements, security, taxes and new generation-related regulatory requirements imposed by statute/rule/regulation/administrative order/court order; or
(b) customer load switches that materially jeopardize either company's ability to recover the anticipated revenue."

[20] Source: Order at 37-38., AEP RSP Case No. 04-169-EL-UNC (1/26/05).

". . . we urge AEP to move forward with a plan to construct an integrated gasification combined-cycle (IGCC) facility in Ohio."

[21] Source: Order, CSP & OP Case No. 05-376-EL-UNC (4/10/06) ("AEP IGCC")

Order at 11-12 "The Application proposes that all reasonably incurred costs related to the IGCC facility be recovered in three phases."
"The first phase will recover preconstruction cost, such as an engineering and scoping study."
"Phase II costs are the *carrying costs on the cumulative investment* in the generation facility * * * carrying costs will include carrying costs deferred after the EPC [engineering, procurement and construction] contract is executed."
"Phase III covers the operating life of the IGCC facility. Phase III costs are the actual capital costs, carrying costs and operating costs of the plant..."

[22] Application at 9. AEP IGCC Case No. 05-376-EL-UNC (3/18/05)

AEP Estimated IGCC, with carrying costs, per the Application was $1,270,488,000: "The current projection of the total cost of construction of the IGCC facility, without carrying costs, is $1,033,000,000. The estimated carrying costs are $237,488,000."

[23] The SRT and FPP, since they are based on recovery of actual costs are trackers. The AAC and IMF are simply percentages of "little g" and do not "track" recovery of actual costs.

[24] Source: DE-Ohio tariffs and OCC Estimate of "RSP - New Components impact on Residential Generation Revenue (9/18/06)."

The AAC was set by the PUCO at 6% of little g for Res. for 2006 and the IMF was 4% of little g for Res. for 2006. The estimate for residential "Little g" used was the $.039/Kwh from the RSP case. Average SRT and FPP rates were calculated based on the four actual quarterly rates per the DE-Ohio tariffs.

[25] Source: 11/23/04 Entry on Rehearing and 1/19/05 Entry on Rehearing, CG&E Case No. 03-93-EL-ATA ("CG&E RSP") and CG&E tariffs sheets and CG&E website.

For Residential, beginning in 2006:

- The AAC is bypassable for the first 25% of load switching and nonbypassable for the remaining 75%. (Sheet 51)
- The SRT is non-bypassable. (Sheet 56)
- The FPP is bypassable. (Sheet 53)
- The IMF is non-bypassable. (Sheet 54)

For Non-Residential, in 2006:

- The AAC is bypassable by the first 50% of load switching, subject to notice requirements to CG&E and agreement with other provisions per CG&E's tariffs. (Sheet 51)
- The SRT is bypassable, subject to notice requirements to CG&E and agreement with other provisions per CG&E's tariffs. (Sheet 56)
- The FPP is bypasable. (Sheet 53)
- The IMG is non-bypassable. (Sheet 54)

[26] Source: Order at 2-3, DPL Case No. 02-2779-EL-ATA (9/2/03)

"In its ETP opinion, the Commission, among other things, allowed DP&L a market development period (MDP) of three years, ending December 31, 2003..."

[27] Source: Order at 13, DPL Case No. 02-2779-EL-ATA (9/2/03)

"...the signatory parties agree that DP&L's MDP will be extended through December 31, 2005." "After the MDP terminates on December 31, 2005, the stipulation would set up a rate stabilization period (RSP)." (5/28/03 Stipulation at 11-12, RSP "beginning January 1, 2006 and ending on December 31, 2008.")

[28] Source: OCC Witness Haugh Schedule Replacement MPH-1, DP&L Case No. 05-276-EL-AIR

$206 million is revenue from the RSS charge for an additional two years (2009-2010), plus a new EIR charge for 2007-2010, both of which were not contemplated in the prior DP&L case. However, the $206 million does not take into account that the PUCO also allowed a 2.5% residential discount for 2006-2008 with revenues estimated at $21 million. Therefore, the net increase is an estimated $185 million is a more appropriate representation of the increase, but the $206 million dollar increase due to two years' additional RSS and the new EIR charge is not completely incorrect.

[29] Another point about the DP&L settlement that is troubling is that when parties enter into an agreement in good faith, they ought to be able to count on the benefits of the bargain and be held accountable to provide the benefits to the other party as negotiated. By allowing further increases, the delicate balance of the first agreement was upset in that consumers did not get what they bargained for. This makes reliance on settlements achieved through negotiations more difficult. It used to be that a party could count on the other signatories to carry forward with the terms agreed to. Unfortunately this is becoming less of a certainty.

[30] Source: NOPEC 2005 Annual Report at 3

[31] Source: OCC 2005 Biennial Report on the State of Electric Restructuring at page 4.

NOPEC represents "113 communities with approximately 455,000 residential and small commercial customers."

[32] Source: NOPEC 2005 Annual Report at 3.

[33] Source: PJM Member List includes CSP, DP&L and OP.

[34] Source: MISO Member List includes ATSI (FE) and DESS (Duke Energy).

[35] Seams Issues are barriers and inefficiencies resulting from equipment limitations and differences in market rules and designs, operating and scheduling protocols, and other control area practices which inhibit or preclude the ability to conduct capacity and energy transactions across control area boundaries.