Senate Energy and Public Utilities Committee

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TESTIMONY OF JANINE L. MIGDEN-OSTRANDER

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BEFORE THE SENATE ENERGY AND PUBLIC UTILITIES COMMITTEE

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Good morning. I am Janine Migden-Ostrander, the Consumers' Counsel for the State of Ohio representing Ohio's 4.5 million residential households. As the largest stakeholder in this process, providing all of Ohio investor-owned utilities with at least 40 percent of their revenues, residential consumers are the financial backbone of the electric industry. What policymakers do today will have a profound impact on the millions of families across this state. The Office of the Consumers' Counsel commends Governor Strickland for his smart approach to developing an energy plan that is forward thinking and serious about Ohio's energy future. We also commend the General Assembly for giving considerable time and attention to these issues and asking the questions that need to be asked in order to develop a plan that will hopefully benefit **all** segments of the Ohio community. The final plan should provide for the implementation of least-cost and least-risk options over the short- and long-run, and should open the door for nontraditional advanced technologies to emerge such as energy efficiency and renewable energy. Each of these concepts will be discussed in more detail below.

While much of the testimony this Senate committee has heard, to date, has focused on the needs and wants of Ohio big business - from the utilities to the manufacturers - my testimony will address the concerns of another big customer class – the residential customers. The profile of this class is widely varied -- from the working family trying to put aside enough money for their children's college education, to the low-income customers struggling to stretch dollars to cover the bare essentials of food, shelter, medicine and utilities. Ohio's residential electric customers are also a big stakeholder in this issue and, thus, need and deserve to occupy a prominent seat in this debate. As their attorney, I thank you for the opportunity to address you today.

Detailed discussions of deregulation, regulation or hybrid approaches matter greatly to us. However, to Ohio's working families, the discussions are quite simply about the bottom line. My clients are your constituents. We hear that they are very concerned about their cost of living issues: providing for their families, keeping their jobs, health care costs, maintaining a home and having reliable and affordable utility services.

When all is said and done with this legislation, residential consumers fundamentally will want to know two things from us:

1) How much is their electricity going to cost and are we doing everything possible to keep costs down; and,

2) What will we do to ensure their utility services are reliable?

We must not lose sight of this observation as we move forward to forge Ohio's energy future. We must ensure that Ohio's institutions and procedures are sound so that they will serve Ohioans today, tomorrow, and in the long run. Losing sight of this observation risks inviting recurring demands for legislative "fixes" that could endanger Ohio's energy future.

With this in mind, the legislation should focus on the following two policy objectives:

1. Least-cost planning is needed to protect customers and to keep service affordable; and

2. Least-cost planning needs to be the foundation of Ohio's plan for the future in order to assure a diverse portfolio of energy options.

This testimony will provide a brief historical view of where we have been so that it can be clearly understood that the hybrid approach discussed in this legislation is not mistaken for re-regulation. I will then discuss the changes the Office of the Ohio Consumers' Counsel (OCC) believes are necessary to protect customers regarding the electricity security plan and going to market and in terms of the advanced energy plan.

I. Least Cost Planning is Needed to Protect Customers and to Keep Service Affordable

A. General Overview

Least-cost services and planning for the consumer in the short and long-run needs to be at the centerpiece of this debate. Much of the discussion thus far has focused on providing utilities with an incentive to do what they should already be doing when they have an obligation to serve. Further, the debate has focused on quick cost recovery mechanisms and valuations of electric generating assets that would result in pricing electricity at above the cost of service. Every incentive given, every quick recovery mechanism that does not allow for a full review of costs, to assure that dollars are efficiently spent and that there is no double recovery, and every valuation of generating assets (that comprise the lion's share of a customer's bill) above actual value, takes dollars out of the pockets of residential customers.

We are already being told to get ready for dramatically increased electricity prices to cover new construction of generation plants, environmental compliance, and infrastructure improvements. If Ohio takes a hybrid approach to regulation, the above-mentioned additional costs would likely be placed on the backs of customers in the form of front-loaded payments. To counter this situation, clear statutory guidance must be provided to the regulatory authorities and the utilities regarding how rates would be determined, what customers may be asked to pay over time, and how those costs will be determined. We need full due process in proceedings and we need to understand the risks that are attached to decisions.

When Senate Bill 3 was passed, too many of the tough decisions were deferred to the Public Utilities Commission. Ohio should not allow history to repeat itself. Ohio needs specificity in the bill, and a regulatory process that is transparent should result from such specificity. Deals of "sign now, pay later" have been struck under S.B. 3, and they invariably result in controversy and uncertainty that works to the disadvantage of residential customers and the Ohio economy.

I ask that you consider the following facts with respect to the customer population:

- According to the Office of Strategic Research in the Ohio Department of Development, there are 807,345 households in Ohio at 150 percent of the poverty guideline. That is approximately 18 percent of all Ohio households that are that are eligible for assistance through the Percentage of Income Payment Plan Program (PIPP), Home Energy Assistance Program (HEAP) or the Home Weatherization Assistance Program (HWAP).

- The number of households at 175 percent of the poverty guideline jumps to 1,066,618, nearly one quarter of all Ohio households. That translates into an additional 259,273 low-income Ohio households that do not have access to most of the programs and who must somehow find resources to pay rising energy bills.

- According to information from the Midwest Energy Efficiency Alliance, in 2004, energy bills for low-income Ohioans were $740 million more than what is generally accepted as affordable. In 2006, actual low-income energy bills exceeded affordable energy bills by $1,156 million, an increase of 84.5% since 2002.

- The number of gas and electric company disconnections for the twelve-month period ending July 2007 is 382,786, a ten-percent increase over the previous year.
- Natural gas rates have more than doubled over the last five years, and electric rates have, or will, increase significantly during the period covered by the rate stabilization plan (RSP).

- There have also been significant increases in a number of sectors where customers are not able to respond effectively to changes in prices. For instance, gasoline prices often exceed $3.00 a gallon, a particularly high burden for rural or poor households that do not have access to public transportation and do not have adequate alternatives.

- To compound matters, every major gas, electric, and water company has either filed or announced that they will be filing shortly for rate increases. Many utilities cite the high costs of infrastructure improvements as the main cost driver for higher rates.

This situation described above underscores the point that Ohio cannot afford to reward utilities with consumer cash when such customer payments are based upon service that the utility should be doing as part of its job. The job of the utilities is to provide reliable service at a just and reasonable price. Policymakers should give equal weight – if not more – to the consumers of this state who pay all the costs.

B. Regulation, Deregulation and Hybrid Regulatory Structures

At the outset, it is important to correct any misconceptions that may have developed that this proposed legislation moves us back towards re-regulation. It is **not** re-regulation, but rather a hybrid that allows the utilities to navigate between markets and regulation as it serves their purposes to protect their interests. It works like this: If a utility wants money for power plant construction, environmental costs, fuel costs or for just agreeing to be the power supplier, etc. they apply to the Commission and get their money. On the other hand, if consumers want to question the utilities' rate of return or their profits from selling power from their depreciated power plants, they are quickly reminded by the utilities that they are deregulated and working within a competitive market and thus we are not entitled to this information.

Under traditional regulation, the utilities were compensated based on cost of service and were given the opportunity to earn a fair and reasonable return on their investments. Rate increases only occurred in a rate case which was a nine month process. "Issue-specific ratemaking" (e.g. reviewing an expenditure selected by the utility) did not, and does not exist for the electric utility industry in Ohio. Statutes and rules clearly set forth what could or could not be recovered in a case. Customers only paid for what they were receiving and nothing more – a fair and reasonable exchange. Customers did not finance multi-billion dollar power plants before they were placed into service, and customers did not take on the risk that was assigned to the shareholders who earned a return for that risk. Under traditional regulation, utilities were viewed as stable because they were granted an opportunity to earn a reasonable return to compensate them for their services.

Due to increasing costs for generating electricity services and significant cost overruns that were passed on to consumers in the form of high rates, a decision was made by the General Assembly (i.e. in S.B. 3) that relied upon competitive markets to provide better protection for customers than had been provided under traditional regulation. The theory was that competition requires efficiency because an inefficient competitor would not survive in the market. Given that power plant generation is the most significant cost in a customer's electric bill (more than 40% on average), the market was expected to discipline power plant producers to build lower cost, more efficient plants and operate them more effectively. Relying on the competitive market was expected to even out prices and eliminate the competitive disadvantages for energy intensive manufacturers located in areas of the state where rates were high.

Unfortunately, competition never developed as hoped for. During the Market Development Period ("MDP"), utilities requested and were granted approximately $11 billion dollars in stranded cost recovery without an evidentiary hearing designed to probe the reasonableness of these costs. With consumers saddled with unreasonably high stranded cost payments, it was impossible for them to shop and find value. This is because the amount of payment to the utility that the customer could avoid by shopping was less than the market price. If stranded costs had been appropriately calculated the generation amount of the bill that customers would have been able to avoid would have been equivalent to, or higher than, the market price and competition would have developed. It was designed for failure, and fail it did.

Not surprisingly, at the end of the MDP, few residential customers shopped for their generation service. I am reminded of Louis, the Vichy Officer in the film *Casablanca* who when asked why he is shutting down Rick's café, utters, "I am shocked, shocked, to find that gambling is going on," just as the croupier hands him his winnings. That competition would not work given the faulty design, is no surprise here.

The Rate Stabilization Plans (RSP) that governed the pricing of generation services after the MDP provided a hybrid approach that brought revenue stability to the utilities and limited further development of the competitive market. The electric utilities devised generation rates that included large non-bypassable elements that were designed to limit or eliminate competition for generation service. OCC appealed several of the RSP and related cases. The Supreme Court of Ohio reversed, in part, three of the decisions and vacated a fourth. Hybrid plans were settled by parties to those cases in huge "opaque box" stipulations in which it was difficult, if not impossible, to determine the service for which a customer was paying.

The FirstEnergy RSP provides an example of the basic structure for such "interim" plans. In areas served by the FirstEnergy companies, customers were required to pay a so-called "Rate Stabilization Charge" that coincidentally equaled the generation transition charge (i.e. a stranded cost charge) that by law expired at the end of the MDP. Depending on the service territory, every residential customer continued to pay, on average, an additional $15 to $20 **per month** in non-bypassable charges after the generation transition charge had supposedly expired.

As part of the settlement related to the FirstEnergy RSP, parties agreed that FirstEnergy could defer the fuel costs incurred from 2006 through 2008 -- the RSP period -- for recovery beginning in 2009. Due to a recent Supreme Court decision, however, FirstEnergy is now seeking recovery of these costs at this time. The price tag -- unknown at the time of the Commission Order -- is $390 to $400 million dollars. This amount could be recovered without audits and hearings on the merits and prudency of the FirstEnergy expenditures. Such regulatory review occurred in fuel proceedings under regulation. Hybrids with opaque boxes should be avoided.

For Duke Energy,[1] a settlement was reached and approved over the objections of OCC. The Rate Stabilization Plan settlement established a framework for cost increases in which consumers were required to pay future costs without knowing what the ultimate price tag would be. There were four buckets of costs established under which the company in a much shorter process than that afforded in a rate case is allowed to file for rate increases. OCC opposed the final decision, in part because we believed the deal was too generous to the utility and that customers have a right to know what they are going to be paying for and to understand whether that is the best

[1] The utility serving the Cincinnati area at the time was the Cincinnati Gas & Electric Company. The Duke-Cinergy merger eventually led to renaming the company "Duke Energy Ohio, Inc."

option for them. As a result of the plan, rates have fluctuates both up and down, with the rate impact on generation rates exceeding at times, 40 percent.

In American Electric Power, the RSP allowed the Company to file to increase rates over a three year period up to 33 percent in the Ohio Power service territory and 21 percent in the Columbus Southern Power service territory. Moreover, the Commission included language that invited AEP to separately file for the recovery of costs associated with the development of a new power plant. As the result of a subsequent proceeding, customers have paid AEP $24 million for concept work on a plant that, at best, is years from providing any service to customers. AEP has made no assurances that in the event that the plant is built in Ohio, it will not sell the plant without Commission approval, a situation that would leave customers having made payments with no corresponding benefits. Moreover, OCC questions a plan that saddles customers with the highest cost capacity while selling the cheaper capacity that customers have already paid for – out of state.

In the Dayton Power and Light (DP&L) RSP case, a settlement was reached by my predecessor under which caps on rate increases were set forth through 2008. This was after extensive negotiations in which there was a lot of give and take to reach an agreement. Despite a Commission order stating that such rates would be uncapped under no circumstances, DP&L's application for increases beyond those previously agreed to and to extend the period for an additional two years was approved by the Commission, thus changing the terms of the deal. And to my chagrin, DP&L's representative just testified before this Committee that it would like the continued "flexibility" to increase rates above those it agreed to in the more recent proceeding.

The negotiation process, which was central to Chairman Schriber's testimony regarding rate-setting, has been severely damaged by the inability of parties to enforce long-term agreements. In essence, it is difficult for consumer entities to have faith in a negotiated, long-term rate plan when such agreements are not honored and the Commission consents to changing them. This leaves customers very uncertain about the future path for generation rates. If, under the electricity security plan, consumer groups are asked to engage in a process of negotiation, then consumer groups need assurance that approved settlements will be honored.

All this leads us to where we are now and the critical question is: *What do we do next?* Governor Strickland has put forth a proposal to which we offer the following recommendations that we believe are necessary in order to achieve the excellent principles that the Governor set forth when he announced his plan.

C. Recommendations

1. The decision to go to market or pursue an electricity security plan should be based on which is the least cost option in the short and long-run and NOT on whether there is a market.

Requiring a competitive *retail* market as a prerequisite to competitively bidding in the *wholesale* market for the standard service offer will not work. If that is the criteria, it will be like "Waiting for Godot", because the retail markets in Ohio have been designed not to work. The best criterion for consumers is what is least cost, and it is important to stress here, that one size does not fit all. If you look across the state, retail residential generation electric rates range from $.045 per kilowatt hour for Ohio Power customers to $.085 per kilowatt hour for Toledo Edison customers (assuming the fuel cost application is granted). *(See Attachment A).* Evaluations of recent market transactions reveal that in Illinois, the average price came in at roughly $.077 per kilowatt hour and AEP just bought power at $.054 per kilowatt hour to serve the Monongahela Power load that it acquired. Thus, going to a competitive market for Ohio Power customers may not be a good idea. On the other hand, going to market may be a better option for FirstEnergy customers than creating another opaque hybrid plan. We also have to consider the fact that FE has separated its assets with the intent to sell power on the competitive market. Its investors have a certain expectation as to the revenues FE will achieve through that plan. FE argues that any law requiring it to dedicate its power to Ohio ratepayers is unconstitutional. If FE foregoes the opportunity to go to market in order to make its generation assets available in Ohio, it will be at a very steep cost to Ohio ratepayers and at a price that may well exceed the market. As the utilities have pointed out in their testimony, they must answer to their shareholders.

In order to assure that the least cost option is adopted for customers, OCC recommends a process whereby a market price is compared against the electric security plan rate to assure that customers are receiving the least cost option. Moreover, having a market price serves as a check against runaway rates under an electricity security plan by creating a ceiling on how high an opaque hybrid rate can go. Otherwise, if the electricity security rate is too high, then we should go to market.

2. The details governing the electricity security plan must be clarified.

There are a lot of details that need to be clarified in the electricity plan in order to protect consumers. First, the proposed electricity security plan starts with the premise of valuating existing generation taking into account several factors. How generation will be valued is unclear. Chairman Schriber indicated that it would be somewhere above cost of service. The utilities argue that generation should be valued at replacement cost or market price. Such ambiguity leaves little comfort for customers. Given that the customers have already paid for the depreciated generating plants including through payments of stranded cost, OCC believes the plant assets should be valued at cost. Otherwise, customers will be double-paying the utilities for the cost of the generating plants. This is problematic because plant assets will be valuated not in accordance with costs that can be verified, but based on the Commission's discretion.

The second issue of concern is the dramatic policy sea change overturning more than a hundred years of traditional regulation. Historically, customers have paid for generation that was used and useful. The only exception was for generating units that were 75 percent complete and then only 10 percent of the interest costs could be included in rates. This proposed legislation stands that principle on its head by granting total discretion to the PUCO to determine at what point a plant can be included in rates and how much of the cost customers must take on. It transfers the risk for new technologies from the shareholder to the consumer. Think of Zimmer near Cincinnati that was 97 percent complete as a nuclear plant and had to be converted to a coal plant at a significant cost overrun. This legislation does not call for caps on the cost or competitively bidding for the generation under the electricity security plan. Thus, there are no protections against customers paying huge costs for new construction. I am concerned that the history of cost overruns in Ohio will repeat itself. While OCC opposes this change, at a minimum, the legislation needs to provide clarity over the limits of rate impacts and risk-shifting customers will have to endure. Moreover, at what point can consumers be asked to pay? Is it reasonable to seek cost-recovery from consumers before there is a shovel in the ground like the Commission decision regarding the proposed AEP IGCC plant? Will customers be limited to paying 10 percent of the costs or a much higher cost? 30 percent? 50 percent? 100 percent? The proposal conditions the cost recovery on a certificate of need, but the legislation provides no insight into how rigorous a review will be undertaken and if that review will require least cost planning. In order to assure that we are pursuing least-cost options and that the power is needed, OCC recommends that the statutes in Chapter 4935 relating to long-term forecasting and integrated resource planning and Chapter 4906 relating to Power Siting Board certification of need, which were repealed in Senate Bill 3, be reinstated.

Yet another concern is the endorsement of single issue ratemaking, which like granting early recovery for construction, again unravels decades of traditional regulatory precedence designed to balance the interests of the consumers with those of the utility. Allowing the utilities to file for and obtain increases for infrastructure improvements and power plant construction outside of a rate case can produce runaway rate increases. In this regulatory scheme there is no effort to review areas of the utilities' business where costs have decreased and there is no effort to review the utilities' rate of return, which can all be used to offset the requested increases in order to maintain the theoretical balance discussed above. It is of great importance to stress here that the subjects of the single issue ratemaking involve costs that may be well into the billions of dollars. Both power plant construction and infrastructure upgrades require very substantial cost commitments that will be paid for by the consumers. In order to mitigate the potential for rate shock, regulators should be reviewing the entire utilities' accounts and profits and rate of return to find offsets to these costs. Further, clarity is needed as to the process that is envisioned here. Will the utilities be required to set forth in a hearing the entire infrastructure maintenance plan with the opportunity to increase rates annually at levels that are capped and subject to an audit? Will there be adequate due process so that OCC and other intervenors will have sufficient time to conduct discovery, prepare testimony or hire consultants as needed? Or will the process resemble that of some of the RSP's where utilities file for increases that are granted in the space of months with no real roadmap of what the total cost will be and hence, limited opportunity to manage the costs? Consumers need and deserve a fair and transparent process.

The environmental costs passed on to consumers require discussion. If the utility goes to market, the environmental costs get absorbed in the overall regional market price. This is what SB 3 requires. Under the electricity security plan, however, customers will be responsible for paying environmental costs in the billions of dollars. (Recall FE President Tony Alexander's testimony that the cost for environmental upgrades at Sammis was $1.5 billion which was just one Ohio plant.) Further, consideration should be given to the potential costs to comply with greenhouse gas (GHG) requirements once Congress passes laws to regulate carbon dioxide.

All of this adds up to very significant costs that leave me wondering if at the end of the day, customers of some utilities will be better off with a market price instead of an electricity security plan. This is why it is so critical to compare the market price with the electricity security plan. Where we start in the electricity security plan is critical. *(See Attachment B).* If we start at cost of service for valuating the generating assets and then add billions of dollars for infrastructure maintenance plus billions for new construction plus billions for environmental costs, we will end up with very steep price increases that may be managed through phase-ins and deferrals (with interest) of rate increases. On the other hand, if the starting point is somewhere above cost, and worse case – at market or at replacement cost as the utilities argue - then adding billions for infrastructure maintenance and billions for new construction and billions for environmental costs, will result in customers experiencing rate shock. If the costs are managed through phase-ins and deferral, customers in Ohio will be paying very high rates for a very long time to come. If rates are manipulated through deferrals and phase-ins so that they stay just below the market price, customers may be led to believe that the electricity security plan is better when in fact the market price is lower overall.

Once the customers are made to pay for all these costs under the electricity security plan, how difficult will it then be to go to market? Policy decisions need to be made in the legislation regarding what obligations customers who switch will have for paying for these very expensive projects. Theoretically, all generation costs should be able to be avoided or bypassable if an alternative supplier is chosen by a customer. However, if they are avoidable, consideration must be given to the remaining captive customers – largely the residential – who do not have retail options. These captive customers would have to pay not only their costs, but also those of the mostly large customers who switch to retail marketers. These critical policy questions should be addressed in the legislation.

3. Transparency is a laudable goal that should be incorporated into all proceedings before the Public Utilities Commission in order to restore public confidence in the rate-determining process.

Governor Strickland outlined a requirement for transparency which is to be commended and is very much needed. "Transparency," as it relates to proceedings before the PUCO requires that agreements not only between the electric distribution utility and customers, but also the affiliates of electric distribution utilities and customers be examined. S.B. 221 contains a provision that supports such an examination, but modifications are needed for the legislation to address the situation. Customers need transparency in the market to assure that the transactions are arms-length, that there is no market manipulation and no market power. For the market to function fairly and for competition to thrive in a way that produces customer benefits is an absolute must. However, transparency in the electricity security plan is equally important. Transparency means having sufficient time to analyze and understand the numbers in these cases. It means having a clear picture in a negotiated settlement as to what customers are agreeing to pay. Settlements that set up guide paths for increased rates without knowing upfront what those increases will be create uncertainty and potentially subject customers to large increases. It is a basic concept in a settlement between parties that everyone knows and understands what they are getting and at what cost. We need transparency to ensure integrity in the process.

The proposed legislation also addresses another form of transparency and that is having access to all side-deals in a settlement. OCC supports this. However, OCC recommends that the presumption that the information is privileged be removed. Instead, the information should be provided as confidential under a protective agreement. However, any party should have the right through the appropriate legal process to challenge whether the information should be concealed from the public. As the PUCO has found, there may be instances where the information contained in side-deals are not trade secrets, and the public should have a right to see such information. Those concerns are not theoretical, but based on experience. In the recent Duke RSP case, OCC requested copies of the side-deals which the Commission denied. The Supreme Court of Ohio reversed the PUCO decision paving the way to obtain these side deals. One such agreement involved the City of Cincinnati, and the public record reveals the existence of other agreements that involved Duke's affiliates (i.e. Duke Energy Retail Sales, a certified supplier having no sales, and Cinergy Corp. that is not a certified supplier). These deals have cost residential customers a lot of money and at the time of the hearing, there was no ability to address this. Thus, making this information available is essential and welcomed.

A presumption of privilege which may not be legally sustainable in other circumstances acts as a gag order on OCC and other intervenors. OCC believes it should maintain the right to argue if a privilege should be attached. A public discussion within the parameters of the case on whether residential customers should subsidize large industrial customers may well be warranted. Should the struggling low and moderate to middle income customer pay a portion of an industrial customers' rate increase? And does each and every industrial customer that belongs to an intervenor group *need* the subsidy provided in part by the residential consumers? These are policy decisions that should be made in the light of day.

Another issue with respect to transparency is the controversy regarding whether special contracts entered into with the utility and/or its affiliates and an industrial or commercial customer will be made available to intervenors. If residential customers are going to pay more, they have a right to know about it and they should have a right to question whether large customers need the subsidy more than the poor customer who must pay it.

II. A Diverse Portfolio of Energy Options will be Needed to Assure Continued Protection for Customers in the Long-Run.

Least-cost planning requires conducting an analysis over a twenty year horizon to determine what is in customers' best interests. If we look towards the lowest rate today without considering its concomitant impacts on the future, we could be penny-wise and pound-foolish. Consider the following facts:

- There are approximately 67 years of economically recoverable supplies of natural gas left in North America. Nevertheless, the reliance on natural gas to fuel power plants is increasing – projected at 24 percent regionally by 2010 as opposed to 11 percent in 2000.

- Natural gas prices have more than doubled in the last several years and as the United States seeks supplies of natural gas from overseas, we will be competing with Europe and emerging countries like China and India for supplies from countries like Venezuela, Algeria and Nigeria.

- Worldwide demand for electricity is expected to double by 2030. The growth in electricity demand in the United States is projected to increase by 40 percent by 2030.

- Just as the cost of natural gas will continue to rise as more countries compete for diminishing supplies, the cost for coal fired plants will increase dramatically as well, due to environmental compliance with GHG regulations and other existing regulations.

- The price of new nuclear plants is estimated at $4,000 per kilowatt – a high price tag; however, that may very well be an optimistic projection. Remember when they said that nuclear would be too cheap to meter?

Given this challenging outline of our energy future, I commend Governor Strickland for including energy efficiency and renewable energy to help meet our growing needs. Energy efficiency, which has historically been under-utilized as a resource in Ohio, has a major role to play to help offset the tremendous rate increases that we are all staring at. And contrary to testimony you have heard from others, renewable energy is not more costly than new nuclear capacity or clean coal plants with carbon capture and sequestration. Renewable energy is competitive, if not less costly than these options and importantly has no fuel costs. With renewable energy and energy efficiency, we need not worry about rising fuel costs, scarcity of fuel supply, environmental costs, increased water usage, waste disposal costs and concerns, or environmental externalities associated with traditional fossil fuel and nuclear capacity. *Attachment C* is a chart which compares the costs of the various technologies.

The basis that renewable energy and energy efficiency are among the least cost options – without even considering all the other attendant benefits – is reason alone to aggressively tackle an energy plan that features these solutions, front and center. With respect to renewable energy, the proposed legislation would call for the development of a 12.5 percent renewable standard by

2025 with a solar energy set-aside to promote that industry in Ohio. OCC believes we can and should do better than that if we want to protect consumers now and in the future. The requirement should be 25 percent by 2025. While Ohio is one of the largest energy users in the nation, this target would not be inconsistent with some of the other states with usage in the top tier. *(See Attachment D).* Moreover, of the roughly 25 states that have passed renewable portfolio standards, their requirements have mostly been more aggressive than that proposed in this legislation. *(See Attachment E).* It should be noted that FE, AEP and Duke are complying with renewable energy standards in other states.

In addition to requiring a higher level of renewable energy, OCC recommends that there be specific benchmarks which every state but one includes in their renewable portfolio requirement. This is the only way to guarantee that progress is made on a planned, incremental basis. This should not be left to the discretion of the Commission. Moreover, there should be penalties tied to a percentage above the value of a renewable energy credit that attaches for noncompliance. This is necessary to ensure utility compliance with the law.

When faced with planning to meet the growth in demand, there is a choice of adding new capacity or decreasing demand. When weighing the cost of the two options side-by-side, energy efficiency wins as the least cost option to maintain reliable service. OCC supports the enactment of an energy efficiency resource standard. The Governor's plan calls for 25 percent of a utility's load growth to be met by energy efficiency. The 20 year PUCO projections of electricity growth (2003-2022) in Ohio averages 1.2 percent per year. Therefore, the Governor's target translates into approximately .3 percent average annual savings of the existing electricity consumption in

Ohio. This is a good and necessary start and it is OCC's hope that the targets will become more aggressive in terms of reducing overall demand. OCC recommends raising the bar on energy efficiency. The annual percentages of total load (in MWH) savings targets recommended by OCC are 0.3 0.5, 0.7, 0.8, 0.9, and 1.0 percent thereafter of incremental annual demand side management (DSM) savings respectively (so that in year six Ohio is saving 4.2 percent of sales cumulatively going up to eight percent by 2018). *(See Attachment F).* As 2018 approaches, the General Assembly can revisit the issue. The proposed legislation also calls for a 10 percent reduction in peak demand by the year 2020. Since around 10 percent of a utility's capital investment goes to serve one percent of its peak load, and since peak demand often sets the Regional Transmission Organization (RTO) market clearing prices, the demand reduction target will also save Ohio customers money. The deployment of cost-effective advanced metering infrastructure should help meet the peak demand target. Because Ohio has historically done very little in energy efficiency, there is a lot of low hanging fruit that can help us achieve savings very rapidly and efficiently. Moreover, OCC believes that energy efficiency should be the first resource in a loading order (followed by renewables and clean generating technologies) to meet demand growth and should be exhausted before opting for more costly non-renewable clean technology alternatives. Further, like with the renewable energy portfolio requirements, there needs to be specific benchmarks that must be met annually and penalties for noncompliance.

According to a study, by the American Council for an Energy Efficient Economy, an aggressive energy efficiency program can yield savings for residential, commercial and industrial customers of approximately$3 billion over the first five years of implementation in Ohio. Note that these are savings and not costs. When one speaks of the cost of supply options, there is only the cost.

Given the benefits that can be derived by both energy efficiency and renewable energy, recommendations that a utility should be able to do one or the other to achieve one benchmark should be rejected. It makes no sense to have the two least cost options compete against each other and to require this is short-sighted. Each has a significant role to play which should be championed.

The proposed legislation also authorizes decoupling of sales with revenues. From a customer perspective that means that the utility is assured of getting 100 percent of its authorized revenues. Under traditional regulation the utilities were afforded the *opportunity* to achieve those revenues. The difference is that under decoupling, the utilities get their money irrespective of how well they manage their business. While OCC believes that some form of decoupling may be prudent to encourage energy efficiency, it must only be permitted if the utility makes a significant investment in energy efficiency and there are safeguards attached that limit the customer's exposure to yet additional rate increases.

One final area I would like to address is distributed generation and self generation – used by manufacturers and farmers to offset the cost of power. The issue that has placed Ohio at the bottom of Midwest states in terms of developing these projects is Ohio's failure to enact reasonable standby rates. Standby rates are the rates that self-generators pay the utilities when their units are unable to generate their own electricity. The lack of reasonable standby rates is the economic barrier that stands in the way of Ohio's businesses developing alternative energy. The proposal in the legislation still requires monthly charges and room for argument about the appropriate rate. OCC recommends that an option be made available whereby the monthly charge would be eliminated and self-generators could instead pay the utility to procure the needed power on the market at the market price plus a return to the utility for its services.

A very successful outcome would be if we could tap into our energy efficiency and renewable energy resources including distributed generation contributions long enough to postpone the construction of new coal plants for several years especially in light of the current generation sequestration (CCS) technology. According to a study by the National Coal Council, CCS will not be available for another fifteen to twenty years. If these expensive coal plants are built today, there will be a significant gap between the time when the plants come on line and when CCS is available.

I thank you for the opportunity to present testimony to you today on behalf of Ohio's 4.5 million residential utility customers. In closing, I believe that the proposed legislation presents a framework for Ohio's energy future for which the Governor is to be applauded. However, there is much work that needs to be done. We need clarity, transparency, consumer protection, energy planning that includes maximizing energy efficiency and renewable energy and most importantly, assurances that least cost options will be available to **all** Ohioans. Thank you and I would be pleased to answer any questions you may have.

Attachment A

Ohio Monthly Electric Bills - Average Cents per KWH - Estimated 12/2008
Source: PUCO Ohio Utility Rate Survey as of 9/15/07, Company Tariffs, Assumptions Listed (c)
Based on usage of 750 KWH, Major Residential Tariff at Summer Rates

Updated assumptions 9/25/07: ▲

SUMMARY (¢/KWH)	9/2007 (Sept 2007 rates) Generation-Related (a) G-Related	RTC	Total
AEP - CSP	5.7	0.3	6.0
AEP - OP	4.1	0.3	4.4
Duke Energy Ohio	7.1	0.6	7.7
DPL	6.5		6.5
FirstEnergy - CEI	5.4	2.2	7.6
FirstEnergy - OE	6.4	1.0	7.4
FirstEnergy - TE	5.2	2.7	7.9

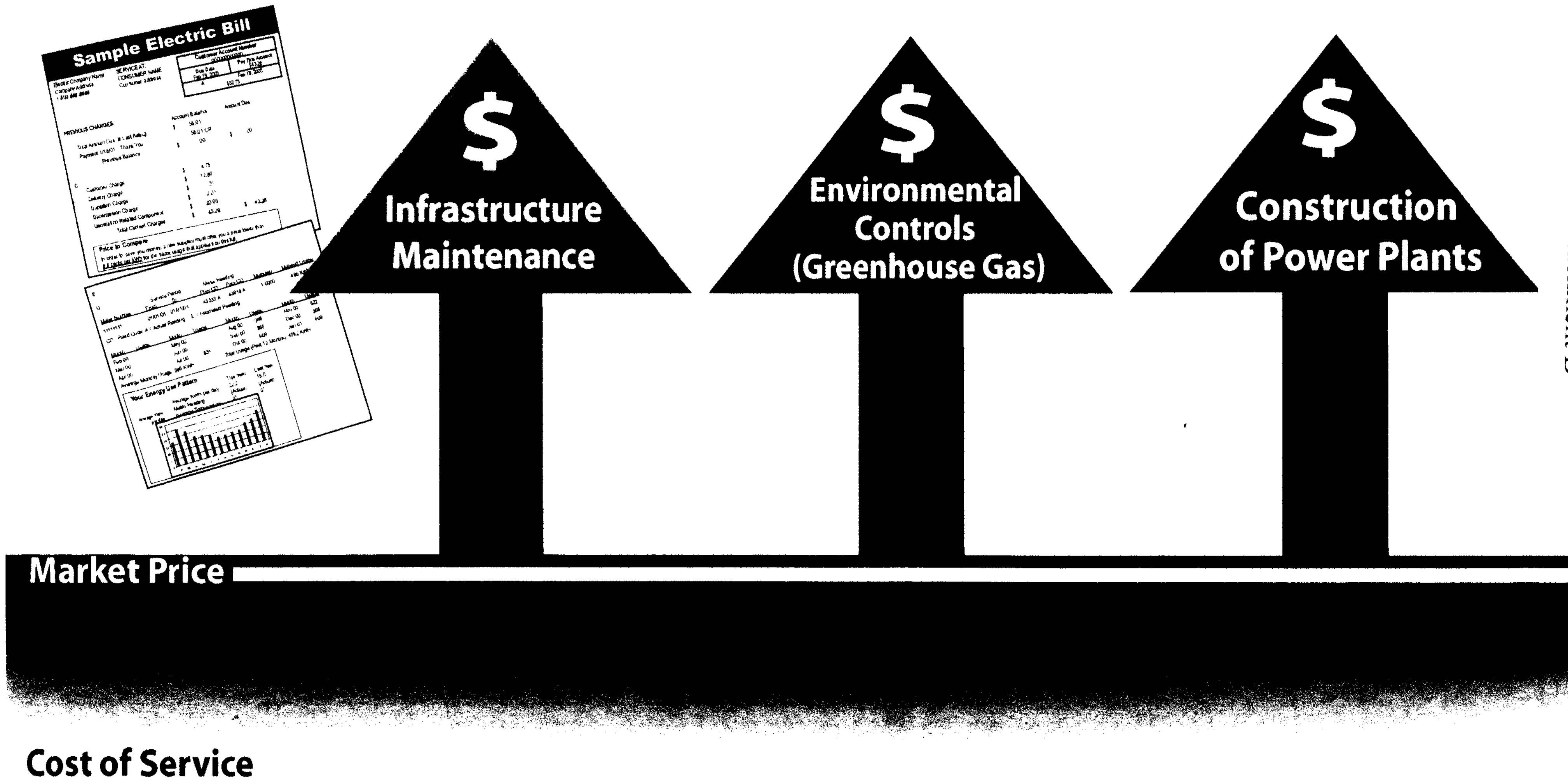
SUMMARY (¢/KWH)	Est 12/2008 (but based on summer rates) Generation-Related (a) G-Related	RTC	Total	
AEP - CSP	6.0	0.3	6.3	
AEP - OP	4.5		4.5	
Duke Energy Ohio	6.6	0.6	7.2	▲
DPL	6.8		6.8	
FirstEnergy - CEI	*6.0	2.2	8.2	▲
FirstEnergy - OE	7.0	1.0	8.0	▲
FirstEnergy - TE	5.8	2.7	8.5	▲

(a) Generation-Related Average Rates by Utility:		Sep-07
AEP - CSP		(¢/KWH)
Generation Service	Bypassable	5.4
(Rate includes 2007 Additional Increase eff 5/1/07)		
Power Acquisition Rider	Bypassable	0.2
IGCC Cost Recovery Charge	Bypassable	
POLR Charge	Non-Bypassable	0.1
Regulatory Transition Charge	Non-Bypassable	0.3
		6.0
AEP - OP		(¢/KWH)
Generation Service	Bypassable	4.0
(Rate includes 2007 Additional Increase eff 5/1/07)		
IGCC Cost Recovery Charge	Bypassable	
POLR Charge	Non-Bypassable	0.1
Regulatory Transition Charge	Non-Bypassable	0.3
		4.4
Duke Energy Ohio		(¢/KWH)
Generation Service	Bypassable	3.8
Fuel & Purchased Power	Bypassable	2.2
Annually Adjusted Component	Bypassable (#)	0.3
Rate Stabilization Charge	Bypassable (#)	0.6
Rate Stabilization Surcredit	Ended 3/29/07	
Infrastructure Maintenance Fund	Non-Bypassable	0.2
System Reliability Tracker	Non-Bypassable	0.0
Regulatory Transition Charge	Non-Bypassable	0.6
(#) Bypassable under certain conditions		7.7
DPL		(¢/KWH)
Generation Service	Bypassable	5.6
Environmental Investment Rider	Bypassable	0.3
Rate Stabilization Surcharge	Non-Bypassable	0.6
		6.5
		(¢/KWH)
CEI		CEI
Generation Service	Bypassable	3.3
Fuel Cost Rider (eff 10/1/07)	Bypassable	
Def Fuel Cost Rider (eff 10/1/07)	Non-Bypassable	
Rate Stabilization Charge	Bypassable (#)	2.1
Transition "E" Credit	Non-Bypassable	-0.7
Transition "F" Credit	Non-Bypassable	-0.4
Regulatory Transition Charge	Non-Bypassable	3.3
(#) Bypassable under certain conditions, subject to SC cap		7.6
OE		(¢/KWH)
Generation Service	Bypassable	4.2
Fuel Cost Rider (eff 10/1/07)	Bypassable	
Def Fuel Cost Rider (eff 10/1/07)	Non-Bypassable	
Rate Stabilization Charge	Bypassable (#)	2.2
Transition "E" Credit	Non-Bypassable	-0.2
Transition "F" Credit	Non-Bypassable	-0.4
Regulatory Transition Charge	Non-Bypasable	1.6
(#) Bypassable under certain conditions, subject to SC cap		7.4
TE		(¢/KWH)
Generation Service	Bypassable	2.7
Fuel Cost Rider (eff 10/1/07)	Bypassable	
Def Fuel Cost Rider (eff 10/1/07)	Non-Bypassable	
Rate Stabilization Charge	Bypassable (#)	2.5
Transition "E" Credit	Non-Bypassable	-0.7
Transition "F" Credit	Non-Bypassable	-0.4
Regulatory Transition Charge	Non-Bypassable	3.8
(#) Bypassable under certain conditions, subject to SC cap		7.9

(b) Generation-Related Average Rates by Utility:		**Dec/Sept 08**	**Rates End 1/1/2009**	**(c) ASSUMPTIONS**
AEP - CSP		(¢/KWH)		RSP effective 2006 - 2008
Generation Service	Bypassable	5.5	5.5	Automatic 3% 2008 Increase
2008 Additional Gen Increase	Bypassable	0.2	0.2	Assume full 4% increase
Power Acquisition Rider	Bypassable	0.2	0.2	PAR ends with RSP end
IGCC Cost Recovery Charge	Bypassable			IGCC Charge Ends 8/07
POLR Charge	Non-Bypassable	0.1	0.1	POLR authorized in the RSP
Regulatory Transition Charge	Non-Bypassable	0.3	0.3	RTC ends 12/31/08
		6.3	**6.3**	
AEP - OP		(¢/KWH)		RSP effective 2006 - 2008
Generation Service	Bypassable	4.2	4.2	Automatic 7% 2008 Increase
2008 Additional Gen Increase	Bypassable	0.2	0.2	Assume full 4% increase
IGCC Cost Recovery Charge	Bypassable			IGCC Charge Ends 8/07
POLR Charge	Non-Bypassable	0.1	0.1	POLR authorized in the RSP
Regulatory Transition Charge	Non-Bypassable			RTC ends 12/31/07
		4.5	**4.5**	
Duke Energy Ohio		(¢/KWH)		RSP effective 2006 - 2008
Generation Service	Bypassable	3.8	3.8	
Fuel & Purchased Power	Bypassable	1.3	1.3	Est. FPP (33% Gen) = Avg. of 8 Qtrs
Annually Adjusted Component	Bypassable (#)	0.6	0.6	AAC proposed in 07-973 (13.8% g) ▲
Rate Stabilization Charge	Bypassable (#)	0.6	0.6	RSC (15% g) stays same as 2007
Infrastructure Maintenance Fund	Non-Bypassable	0.2	0.2	IMF (6% g) stays same as 2007
System Reliability Tracker	Non-Bypassable	0.1	0.1	Est. SRT ($.000515) -Duke proposed 1/07
Regulatory Transition Charge	Non-Bypassable	0.6	0.6	RTC ends 12/31/08
(#) Bypassable under certain conditions		**7.2**	**7.2**	
DPL		(¢/KWH)		**RSP effective 2006 - 2010**
Generation Service	Bypassable	5.6		
Environmental Investment Rider	Bypassable	0.6		EIR auto increase (Haugh MPH-6)
Rate Stabilization Surcharge	Non-Bypassable	0.6		
		6.8		
		(¢/KWH)		
CEI		CEI		RSP effective 2006 - 2008
Generation Service	Bypassable	3.3	3.3	
Fuel Cost Rider	Bypassable	0.3	0.3	FE Estimate for 12/08 (07-1003) ▲
Def Fuel Cost Rider	Non-Bypassable	0.3	0.3	FE Estimate for 12/08 (07-1003) ▲
Rate Stabilization Charge	Bypassable (#)	2.1	2.1	
Transition "E" Credit	Non-Bypassable	-0.7	-0.7	
Transition "F" Credit	Non-Bypassable	-0.4	-0.4	
Regulatory Transition Charge	Non-Bypassable	3.3		**RTC reduced 4/30/09; then thru 12/31/10**
(#) Bypassable under certain conditions, subject to SC cap		**8.2**	**4.9**	**(Est. reduction of 30-35% per FE)**
OE		(¢/KWH)		RSP effective 2006 - 2008
Generation Service	Bypassable	4.2	4.2	
Fuel Cost Rider	Bypassable	0.3	0.3	FE Estimate for 12/08 (07-1003) ▲
Def Fuel Cost Rider	Non-Bypassable	0.3	0.3	FE Estimate for 12/08 (07-1003) ▲
Rate Stabilization Charge	Bypassable (#)	2.2	2.2	
Transition "E" Credit	Non-Bypassable	-0.2	-0.2	
Transition "F" Credit	Non-Bypassable	-0.4	-0.4	
Regulatory Transition Charge	Non-Bypassable	1.6	1.6	RTC ends 12/31/08
(#) Bypassable under certain conditions, subject to SC cap		8.0	**8.0**	
TE		(¢/KWH)		RSP effective 2006 - 2008
Generation Service	Bypassable	2.7	2.7	
Fuel Cost Rider	Bypassable	0.3	0.3	FE Estimate for 12/08 (07-1003) ▲
Def Fuel Cost Rider	Non-Bypassable	0.3	0.3	FE Estimate for 12/08 (07-1003) ▲
Rate Stabilization Charge	Bypassable (#)	2.5	2.5	
Transition "E" Credit	Non-Bypassable	-0.7	-0.7	
Transition "F" Credit	Non-Bypassable	-0.4	-0.4	
Regulatory Transition Charge	Non-Bypassable	3.8	3.8	RTC ends 12/31/08
(#) Bypassable under certain conditions, subject to SC cap		8.5	**8.5**	

Attachment B

The Significance of Plant Valuation on Rates



Attachment C

Attachment C

Technology	IGCC AVG (1)	IGCC AVG (1)	Latest IGCC Project estimate AEP & Duke (2)	Pulverized Coal (1)				Latest PC Plant Estimate (3)	Natural Gas Combined Cycle (1)		Nuclear (4)	Latest Nuclear Project Quote (5)	Wind Actual Cost (6)	Energy Efficiency (7)
Metric				**Subcritical**		**Supercritical**			**2 x 7FB**					
Case #	w/o CC	with CC		w/o CC	with CC	w/o CC	with CC	w/o CC	w/o CC	with CC				
$/kW	$1,841	$2,496	$4,000	$1,474	$2,626	$1,508	$2,635	$2,600	$554	$1,172	$2,000	$4,000	$1,480	$400
LCOE, Cents/kWh*	7.79	**10.63**		**6.40**	**11.88**	**6.33**	**11.48**		**6.84**	**9.74**	**6.70**		**4.90**	**1.3 - 3.2**
% Increase in COE with Capture		36.4			85.6		81.4			42.4				

Notes:

*** 20 year LEVELIZED COST OF ELECTRICITY (LCOE). Includes estimate of capital cost, fixed operating cost, variable and operating cost and fuel cost.**

1. Average of 3 IGCC designs (GE, CoP E-Gas, Shell), "Cost and Performance Baseline for Fossil Energy Plants", Exhibit ES-2, DOE, May 2007. CO_2 transport, storage and monitoring adds <0.5 ¢/kWh, increase in COE ~ 3 cents/kWh (36%).
2. Based on latest IGCC estimates, see 9/10/07 Power Daily, page 5, for Duke $2.0 billion estimate and 6/18/07 $2.23 billion filing of AEP's 629 MW W. Virginia plant.
3. Based on expected cost of Longview supercritical, pulverised coal-fired generating facility in West Virginia at $1.8 billion for 695 MW, or about $2,600/kW, http://www.altassets.com/news/arc/2006/nz9491.php.
4. "The Future of Nuclear Power", Table 5.3, MIT, 2003. These figures do not include an estimated decommissioning cost of $350 million per plant.
5. "Realistic" costs of nuclear power as expressed by AEP CEO Mike Morris, "AEP not interested in nuclear plants", Bloomberg, AP and Staff Reports, 8/29/2007.
6. "Annual report on U.S. Wind Power Installation, Cost and Performance Trends: 2006, DOE. Figures are capacity weighted averages and include federal production tax credit.
7. Levelized cost of saving electricity, Martin Kushler, "The Midwest Energy Crisis and Why Energy Efficiency Should Be a Top Policy Priority", ACEEE 2005. The capacity costs are modeled after a residential direct load control program.

Attachment D

Top 8 Electricity Consumption States and their Renewable Portfolio Standards

	% Required	by Year
1 Texas	2,280 MW	2007
	3,272 MW	2009
	4,264 MW	2011
	5,256 MW	2013
	5,880 MW (5%)	2015
	10,000 MW	2025
2 California	20.0%	2010
	33%	2020
3 Florida*	50.0%	2017

	Tier I (Including Solar)	**Tier II**	**Total**	**by Year**
4 Pennsylvania*	1.5%	4.2%	5.7%	2007
	1.5%	4.2%	5.7%	2008
	2.0%	4.2%	6.2%	2009
	2.5%	4.2%	6.7%	2010
	3.0%	6.2%	9.2%	2011
	3.5%	6.2%	9.7%	2012
	4.0%	6.2%	10.2%	2013
	4.5%	6.2%	10.7%	2014
	5.0%	6.2%	11.2%	2015
	5.5%	8.2%	13.7%	2016
	6.0%	8.2%	14.2%	2017
	6.5%	8.2%	14.7%	2018
	7.0%	8.2%	15.2%	2019
	7.5%	8.2%	15.7%	2020
	8.0%	10%	18.0%	2021

5 Ohio*	25.0%	2025
6 Georgia	0.5%	2007
	1.0%	2008
	1.5%	2009
	2.0%	2010
	2.5%	2011
	3.0%	2012
	3.5%	2013
	4.0%	2014

Attachment D

		Public Utilities		Municipals & Cooperatives	
7	**North Carolina***	0.02% (from solar)	2010	10%	2017
		3.0%	2012		
		3.0%	2013		
		3.0%	2014		
		6.0%	2015		
		12.5%	2021		
8	**Illinois***	2.0%	2008		
		4.0%	2009		
		5.0%	2010		
		6.0%	2011		
		7.0%	2012		
		8.0%	2013		
		9.0%	2014		
		10.0%	2015		
		11.5%	2016		
		13.0%	2017		
		14.5%	2018		
		16.0%	2019		
		17.5%	2020		
		19.0%	2021		
		20.5%	2022		
		22.0%	2023		
		23.5%	2024		
		25.0%	2025		

* Please review attachment for more information

Attachment D

Top 8 Electricity Consumption States and Their Renewable Portfolio Standards

1. Texas
2. California
3. Florida
4. Pennsylvania
5. Ohio
6. Georgia
7. North Carolina
8. Illinois

Texas

As of August 1, 2005, law in Texas requires that 5,880 MW of new renewable generation be built in the state by 2015. (2,280 MW by 2007, 3,272 MW by 2009, 4,264 MW by 2011, 5,256 MW by 2013 and 5,880 MW by 2015) This will be equal to about 5% of the state's projected electricity demand. Also, legislation sets a cumulative target of installing 10,000 MW of renewable generation capacity by 2025. The legislation also requires that 500 MW of the 2025 target comes from non-wind renewable generation.

California

Senate Bill 107, signed on September 26, 2006 by Governor Schwarzenegger requires 3 major utilities (Pacific Gas & Electric, Southern Edison, and San Diego Gas & Electric) to produce at least 20% of their electricity using renewables by 2010. The governor has also set a goal of achieving a 33% renewable energy share by 2020 as a state. Prior to this, SB 1078 required California to generate 20% of its electricity from renewable energy no later than 2017. The 33% goal has been said to be feasible however will have a negative ratepayer impact in the first decade. This negative impact is more than offset by longer term ratepayer benefits over ten years in the 2021 to 2030 timeframe.

Florida

No renewable portfolio standards are currently in place in Florida. However negotiations are ongoing as to the standards they may implement. The state Senate has passed what would be the most stringent renewable energy requirements for electricity generation in the nation. The energy plan would require half (50%) of new electricity in Florida to be generated with renewable energy by 2017. Florida currently generates about 2.5% of its electricity using renewable fuels.

Attachment D

Pennsylvania

Senate Bill 1030 enacted in November of 2004 requires each electric distribution company and electric distribution supplier to retail electric customers in Pennsylvania to supply 18% of its electricity using alternative-energy resources by 2020. There are two tiers of qualified sources that may be used to meet the standard. Tier 1 sources must make up 8% of the portfolio, and include wind, solar, coalmine methane, small hydropower, geothermal, and biomass. Solar sources must provide .5% of the generation by 2020. Tier 2 sources make up the remaining 10% of the portfolio, and include waste coal, demand side management, large hydropower, municipal solid waste, and coal integrated gasification combined cycle.

Ohio

By 2025, the governor proposes that a minimum of 25% of the electricity sold in Ohio must be generated from advanced energy technologies. No less than half of this amount, 12.5%, should be generated from renewable energy sources. At least half of the total advanced energy requirement must be met through assets sited in Ohio, and a specific "carve-out" requirement for solar power must be adopted.

Georgia

Beginning on January 1, 2007, a minimum of 0.5% of the kWh of electricity sold annually for retail consumption in Georgia by each electric service provider shall be from a renewable energy resource in Georgia or be derived from the renewable energy certificate equivalent of such energy. Minimum percentages will increase by 0.5% until January 1, 2014 on an annual basis so that the minimum amount after this date will be 4% of the kWh of electricity sold will be from renewables.

North Carolina

In August 2007 S.L. 2007-397 stated, by 2021 electric public utilities must meet 12.5% of retail electricity demand through renewable energy or energy efficiency measures, and electric membership corporations and municipalities that sell electric power in the state would have to meet a standard of 10% by 2018. Up to 25% of the standard can be met by energy efficiency technologies and after 2018, 40% of the standard can be met through energy efficiency technologies.

Illinois

In August 2007, Public Act 095-0481 set a statewide Renewable Energy Standard and an Energy Efficiency Portfolio Standard. Utilities in Illinois must produce 2% of their power from Renewable Sources in 2008 increasing to 25% by 2025. 75% of the electricity used to meet the standard must come from wind power generation. This law also requires utilities to implement cost-effective energy efficiency measures to reduce electric usage by 2% of demand by 2015.

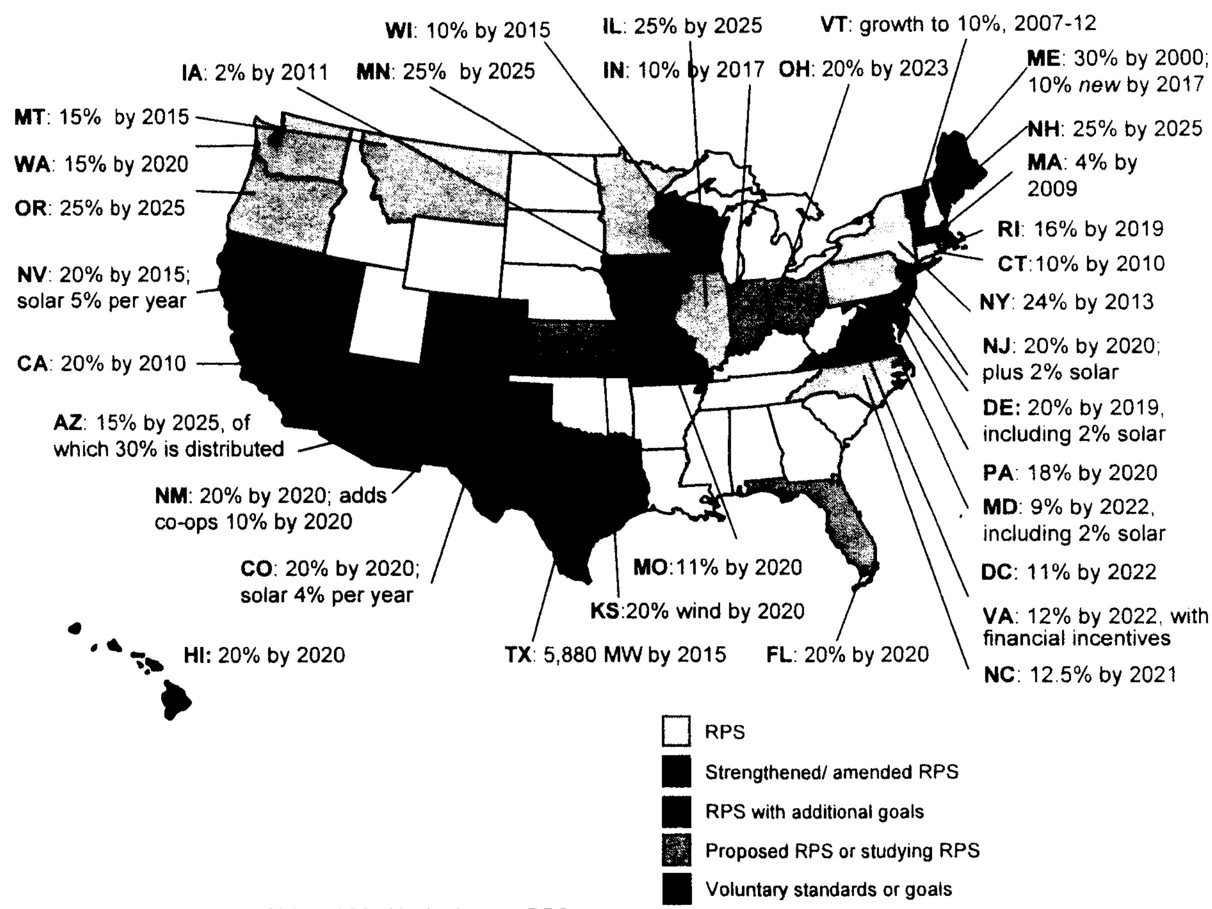
Attachment E

Electric Market Overview: Renewables

Federal Energy Regulatory Commission • Market Oversight @ FERC.gov

Renewable Energy Portfolio Standards (RPS)

- A RPS requires a percent of energy sales or installed capacity to come from renewable resources.
- 25 states and DC now have renewable energy standards. Three more have goals. This summer, North Carolina enacted an RPS, Delaware doubled its requirement, Illinois and Maine turned goals into law, and Missouri enacted a goal.
- States that adopted transmission planning and cost recovery policies to support new renewable generation include California, Colorado, Minnesota, New Mexico, and Texas.



Notes: Minnesota's requirement for Xcel Energy exceeds the state's: it is 30% by 2020; Alaska has no RPS.
Sources: Derived from data in: EEI, EIA, LBNL, PUCs, State legislative tracking services, Database of State Incentives for Renewables and Efficiency, and the Union of Concerned Scientists.

Updated August 30, 2007

Attachment F

Proposed Ohio Energy-Efficiency Resource Standard

	Incremental Annual Savings (% of Sales)	Cumulative Annual Savings (% of Sales)
2009	0.3	0.3
2010	0.5	0.8
2011	0.7	1.5
2012	0.8	2.3
2013	0.9	3.2
2014	1.0	4.2
2015	1.0	5.2
2016	1.0	6.2
2017	1.0	7.2
2018	1.0	8.2