STATE OF NORTH CAROLINA
UTILITIES COMMISSION
DOCKET NO. E-100, SUB 128

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Investigation of the Integrated Resource	)	INITIAL COMMENTS
Plan in North Carolina for 2010	)	BY NC WARN

NOW COMES the North Carolina Waste Awareness and Reduction Network, Inc. ("NC WARN"), through the undersigned attorney, with its initial comments on the integrated resources plans ("IRPs") filed by Duke Energy and Progress Energy in this docket. In order to present evidence to the Commission on the issues presented in these comments, NC WARN requests a hearing on the merits.

Introduction.

1. As a basic premise, both Duke Energy and to a lesser extent, Progress Energy have significantly overestimated the need for baseload power plants over the IRP planning horizon, and as a result, continue to include expensive new nuclear plants and the existing large coal plants in their plans. The result of overly optimistic growth projections and ignoring alternatives to conventional generation is that both IRPs, and more notably Duke Energy's plan, rely on new and costly baseload plants, all nuclear, that will cause electricity bills to increase dramatically over the next decade and beyond. Not only are proposed baseload nuclear power plants not needed, significantly all of the coal plants in the Duke Energy and Progress Energy generation mix can and should be

phased out. NC WARN continues to believe this phase-out can be accomplished through the three prongs of energy efficiency, renewable energy sources and customer cogeneration, all practical and cost-effective measures crucial to a sound economy for North Carolina's future.

Scope of review.

2. The Commission's role in addressing the costs and benefits of generation and demand reduction measures is clear. G.S. 62-2(3a) states that the policy of the State is to find the "***least cost*** mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills." (emphasis added). In addition to approving the least cost mix of generation, efficiency and renewable energy sources, G.S.62-110.1(c) requires the Commission to keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina.

3. By rule, the Commission requires the electric utilities to file annual reports with their forecasts of peak demand growth and how the utility is planning to meet that growth. NCUC Rule 8-60. It is evident that the Commission has determined that the IRP process and review of load forecasts are of primary importance in carrying out the State policy. It is therefore important for the Commission to cast a critical eye on what is presented to it in order to determine the "least cost mix."

4. The development of energy efficiency and renewable energy sources has increased as a significant component of State policy as evidenced in the Renewable Energy and Energy Efficiency Portfolio Standards ("REPS"), pursuant to the provisions

of Session Law 2007-397 (also referred to as "Senate Bill 3"). As a result of our State's increased reliance on energy efficiency and renewable energy sources to meet future growth in electricity demand, there is a concomitant impetus to reduce the dependence on expensive new power plants. The issue directly before the Commission in the present IRP docket is whether to accept multibillion dollar new plant construction or proceed with energy efficiency, renewable energy and related technologies. The lens through which the Commission should review the utilities' load forecasts should reflect State policy – with its emphasis on a diversified mix of energy resources centered on what is found here in our State.

5. Relevant to the IRPs again this year, case law points out that the purpose of the IRP statute, G.S. 62-110.1, is to prevent costly overbuilding. *State ex. rel Utils. Comm'n v. High Rock Lake Ass'n*, 37 NC App. 138, 245 S.E.2d 787, cert. denied, 295 N.C. 646, 248 S.E.2d 257 (1978). This means energy efficiency measures must be seriously incorporated into the utilities' long-term planning in order to reduce load growth and further, renewable energy resources should be developed to meet generation needs. Otherwise, the ratepayers in North Carolina will bear the burden of paying for the new baseload plants proposed by the utilities to meet their projected increase in demand, as well as the risks of the new plants in terms of escalating costs, delay and abandonment.

<u>Excess baseload capacity</u>.

6. While there is no North Carolina definition of a baseload power plant, the Commission requires the electric utilities to file monthly Base Load Power Plant

Performance Reports pursuant to Rule R8-53.[1] That rule requires reports on plant outages and generation capacity on each plant in the utility's nuclear fleet and listed coal plants, as well as all generating plants with greater than 500 MW maximum dependable capacity ("MDC") utilizing coal or nuclear fuel. The 500 MW capacity limit clearly distinguishes between the baseload units that can be operated most of the time and the peaking units that are operated only when required. A useful distinction between the two resource types is the baseload units take time, up to days, to ramp up to full operation while peaking units, such as the natural gas combustion turbines, can generate electricity in a far shorter period of time after being dispatched.

7. Another way to view baseload is to include generating units that operate a certain percentage of the year, with rule-of-thumb estimates ranging from 35% up to 65% or more.[2] The U.S. Department of Energy, in its regulation, 10 C.F.R. 500.2, defines a "base load power-plant" as "a powerplant, the electrical generation of which in kilowatt hours exceeds, for any 12-calendar-month period, such powerplant's design capacity multiplied by 3,500 hours." This includes plants that operate for more than 40% of the year (3,500 hours divided by 8,760 hours in a year). In order to reduce the costs of operating peak plants, the baseload plants should be operated at peak times.

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[1] Duke Energy currently is filing those reports in Docket E-7, Sub 935 and Progress Energy in Docket E-2, Sub 971.

[2] With increasing reliance on renewable energy sources, both the 500 MW definition and the 40% percentage definition may not hold up as a combinations of solar and wind installations function as the equivalent to baseload. See Blackburn, "Matching Utility Loads with Solar and Wind Power in North Carolina: Dealing with Intermittent Electricity Sources," Institute for Energy and Environmental Research, March 2010. www.ieer.org/reports/NC-Wind-Solar.html

8. In its February 2, 2011 filing in Docket E-7, Sub 935, Duke Energy reports in its Base Load Power Plant Performance Report that it currently has 11,854 MW in baseload units.[3] These include the nuclear units, Oconee 1, 2 and 3, McGuire I and 2, and Catawba 1 and 2, and the coal units, Belews Creek 1 and 2, Marshall 1, 2, 3 and 4 and Cliffside 5. With the addition of Cliffside 6, scheduled to begin operation in 2012, this brings Duke Energy's total to 12,679 MW. In its January 27, 2011 filing in Docket E-2, Sub 971, Progress Energy reports it currently has 6,359 MW in baseload units, including the nuclear units, Brunswick 1 and 2, Harris 1 and Robinson 2, and the coal units, Mayo 1 and Roxboro 2, 3 and 4.

9. These total baseload capacity figures are useful in looking at the load duration curves submitted in each of the IRPs. A load duration curve places the MW load on the system for each of the 8760 hours in the year and the resulting curve shows the annual range of load from the lowest load needed for an autumn night as an example to the highest peak on a summer afternoon.

10. Duke Energy provides two load duration curves in its IRP, Figure 3.1 (without energy efficiency) on page 54, and Figure 3.2 (with energy efficiency) on page 57. The load range for 2010 is 4500 MW at the lowest end and almost 17,000 MW at the upper end, with the average 2010 hourly sales approximately 10,900 MW. An important factor emerges from reviewing Duke Energy's load duration curves. When all of its baseload plants are in operation (12,679 MW) they provide more electricity than is

[3] In its Base Load Power Plant Performance Report, Duke Energy includes Marshall 1 and 2, each having an MDC of 380 MW. These plants are operated primarily as baseload units and are included in the Duke Energy totals used herein.

needed for 87% of the hours in a year; in other words, not all of the existing baseload units can operate for most of the year. For most of the year, the plants are either shut down and idle or spinning (still operating but not connected to the grid).[4]

11. Further, in its load duration curves, Duke Energy then forecasts increases in load for each of the hours for 2015, 2020 and 2025.[5] Even using the load duration curve without energy efficiency, Duke Energy still has excessive baseload through 2025; with Duke Energy's projected energy efficiency programs, the current baseload plants provide excessive load for more than 50% of the year. With additional energy efficiency measures or combined renewable energy sources, less and less baseload will be needed.

12. From its twelve-month summary in its January 27, 2011 filing in Docket E-2, Sub 971, Progress Energy shows a total of 6,359 MW for its 500 MW-plus baseload units. In its IRP, at pages B-1 - B-4, Progress Energy designates 7,373 MW as baseload resource type by including several smaller coal plants, Asheville 1 and 2, Robinson 1, in its baseload total. Progress Energy's load forecast curves in its IRP, pages 26-28, show that for approximately 60% of the hours in the year 2010, not all of the designated baseload plants were required to meet its load.

13. In the IRPs, the utilities continue to show a need for baseload additions in their North and South Carolina jurisdictions. In its IRP, page 81, Duke Energy is

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[4] Duke Energy also uses baseload power as part of its pumped storage facilities, pumping water to an upper reservoir to release in peak periods. Duke Energy includes a portion of these baseload plants as part of its reserve margin.

[5] Without explanation, the load duration curves show a substantially greater increase in growth for the hours requiring the lowest load than for peak hours.

proposing two units at the Lee Nuclear Station in Gaffney, South Carolina, forecasted to be in operation in 2021 and 2023. Taking a more realistic approach, Progress Energy advances three scenarios in its IRP, page A-5, while it has apparently backed way from its proposal to build new reactors at the Shearon Harris site, it still continues to include new baseload units in two of its three scenarios. Progress Energy's preferred scenario, Plan A, proposes two jointly owned nuclear plants with it owning approximately 25% share of each plant. Plan B is a much more prudent approach assuming a fairly aggressive control of carbon dioxide. It contains no nuclear units, and the difference in generation consists of natural gas-fired combined cycle plants. Plan C shows two units at the Shearon Harris site in Wake County, but is highly unlikely as the scenario assumes, among other things, low nuclear construction costs.

Escalating costs of nuclear plants.

14. Regardless of the Commission's views on the risks and benefits from nuclear baseload units, the projected costs of this source of electricity have risen exponentially to the point they simply cannot be considered in the least cost mix. The cost of each new nuclear unit nationally is now in the $10 -12 billion range and very few are actively being considered.[6]

15. The IRPs as filed with the Commission contain little justification for the costs of the proposed nuclear units, and even less discussion about the risks associated with going ahead with these large-scale projects. If the utilities continue to go ahead with the

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[6] See for example, Wald, "New Nuclear Plant Projects Stalled by Market Forces," February 8, 2011. ATTACHMENT A.

proposed plants, electricity bills will go up considerably over the next decade (or longer given likely construction delays). These large nuclear units, each more than 1050 MW, would require large reserve capacity in case they are out of operation, increasing the costs even more. The construction and operation of these new nuclear plants are risky in terms of the costs to the ratepayers and taxpayers, as well to the overall economy of North Carolina. The risk is evident in that none of the current nuclear proposals are funded by financial institutions, i.e., Wall Street, and only a limited number of loan guarantees and direct incentives, such as loan guarantees, have been made available from taxpayer-funded Federal government programs.

16. While nuclear costs are projected to continue to rise, the costs of renewable energy have consistently decreased. In his July 2010 paper, Dr. John O. Blackburn reviewed the costs of solar energy and nuclear power plants and determined that in 2010 solar energy has finally become less expensive than nuclear energy.[7] The study included all subsidies for both technologies and compared the cost per kWh generated by each. An important consideration in the Commission's review of the IRPs is that the cost of solar energy and other renewable energy sources is expected to continue to decrease while projected costs of nuclear power plants have risen steadily for the past decade and are expected to increase even more over time.

17. Dr. Blackburn's finding is confirmed in depth by the U.S. Energy Information Administration ("EIA"), an independent statistical and analysis agency within the U.S.

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[7] Blackburn and Cunningham, "Solar and Nuclear Costs – The Historic Crossover: Solar Energy is Now the Better Buy," July 2010. Available at www.ncwarn.org/?p=2290

Department of Energy. The EIA in its most recent Annual Energy Outlook, AEO2011, determined that the updated overnight capital cost estimates for nuclear power plants were 37% above those in the AEO2010 while photovoltaic technologies dropped by 25% in the same year.[8]   Using the definition of "overnight capital cost" from the World Nuclear Association, a supporter of nuclear energy worldwide,

> Capital costs comprise several things: the bare plant cost (usually identified as engineering-procurement-construction - EPC - cost), the owner's costs (land, cooling infrastructure, administration and associated buildings, site works, switchyards, project management, licences, etc), cost escalation and inflation. Owner's costs may include transmission infrastructure. The term "overnight capital cost" is often used, meaning EPC plus owners' costs and excluding financing, escalation due to increased material and labour costs, and inflation.

Note that the last items of financing, increased material and labor costs, and inflation are the components that raise the projected costs of nuclear power costs dramatically, and particularly if construction does not stay on schedule.

18. To date, Duke Energy has not received an operating license from the U.S. Nuclear Regulatory Commission to construct the proposed Lee Nuclear Station nuclear plants. It has not applied for a certificate of public convenience and necessity from the Commission pursuant to G.S. 62-110.1, or its equivalent in South Carolina, for the plants. NC WARN believes it is questionable whether Duke Energy will be able to receive a certificate for a nuclear facility as it faces a high hurdle in showing the nuclear plants compare favorably to energy efficiency, renewable energy and combined heat and power. G.S. 62-110.1(e) states

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[8] ATTACHMENT B is a summary. The complete report with appendix is available at www.eia.doe.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf

> a certificate for the construction of a coal or nuclear facility shall be granted only if the applicant demonstrates and the Commission finds that energy efficiency measures; demand-side management; renewable energy resource generation; combined heat and power generation; or any combination thereof, would not establish or maintain a more cost-effective and reliable generation system and that the construction and operation of the facility is in the public interest.

As noted in these comments the costs of energy efficiency remains low and the costs of renewable energy resources continue to decrease.

Alternatives.

19. In addition to reducing the need for new power plants and the ability to accelerate the closure of the coal plants, the savings associated with energy efficiency and renewable energy are considerable. Although there are additional costs for comprehensive energy efficiency programs, the average cost of the energy efficiency measures is approximately 4 - 5 cents per kWh for residential customers. The average costs of renewables are approximately 9 -10 cents per kWh generated, with solar photovoltaics, i.e., solar PV, approximately 18 cents per kWh with costs decreasing. Customer cogeneration also remains economical as its average costs are approximately 6 - 7 cents per kWh. These are compared to the 13 -18 cents per kWh costs of nuclear electricity if the proposed plants come in on time and on budget.

20. It is readily apparent that rather than treat solar energy or the other renewable energy resources as a part of the least cost mix; the utilities seem only willing to contract for solar capacity at the set aside level in S.L. 2007-397. In essence, the Senate Bill 3 minimum has become the *de facto* ceiling. Progress Energy has already maxed out on the solar set aside and is banking credits for future years. In the

testimony and reports of Dr. Blackburn in the 2009 IRP hearing, Docket E-100, Sub 124, he concluded that almost 18% of Duke Energy's generation can be met by renewable energy sources by 2029 and more than 17% of Progress Energy's generation can by met by the same sources in 2024.

21. In addition to the potential for renewable energy, energy efficiency will play a significant role in North Carolina's energy future. In its April 29, 2010 presentation to the Energy Policy Council, the American Council for an Energy-Efficient Economy ("ACEEE") presented an energy efficiency market potential study demonstrated that an annual electricity savings of 1.2 - 1.6% is achievable over the next decade.[9] Energy savings in the 24 - 32% range were shown to be achievable in North Carolina by 2025. Several other studies that have been presented to the Commission in recent years have shown similar potential savings.[10] Given these savings, it is apparent from the IRPs that Duke Energy and Progress Energy incorporated into their IRPs only the minimal amount of energy efficiency required under the REPS, rather than what was practical.

22. The IRPs do not reflect those who would adopt the energy efficiency measure regardless of any utility-sponsored energy efficiency program. Duke Energy only incorporates its Save-A-Watt programs specifically approved by the Commission in Docket E-7, Sub 831, but nothing more. Outside the utility programs, energy programs range from households who have purchased energy-efficient compact flourescent light

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[9] ATTACHMENT C is ACEEE's powerpoint summary, available at www.energync.net/wdocs/04-29-2010_ACEEE_NC_EPC.pdf

[10] The Energy Policy Council has commissioned LaCapra & Associates for a comprehensive study on North Carolina's energy future. The results of the study are not expected until later this year.

bulbs or replaced appliances and HVAC systems for more efficient models or replaced windows with insulated glass. Large commercial entities such as Wal-Mart have undertaken cost saving in new and existing stores; Food Lion's cogeneration initiatives in eastern North Carolina are worth noting. Many industrial customers have replaced turbines and other equipment, saving energy dollars and making them more competitive economically. Some of these non-utility adopters are free riders on utility programs, or take advantage of Federal and state tax credits, or simply adopt the energy measures because it makes economic or environment sense to them. What is important about them is that their actions are often out of the control of the utilities; they participate in non-utility programs, or save energy in ways that the utilities are unable or unwilling to sponsor.

<u>Ambitious growth projections</u>.

23. The fundamental problem with planning based on ambitious growth projections with only a token amount of energy efficiency is that it necessitates costly new baseload power plants to meet the projected demand. Even a fraction of a percentage point in a growth forecast accumulates considerably over the IRP planning horizon, inaccurately leading to a false conclusion that significant growth in electricity demand is inevitable. Regardless of the source of energy efficiency, the savings should be included in the forecasts at realistic levels.

24. A review of past IRPs shows that both utilities have consistently lowered most of their successive projections of increased electricity demand. In comparing its 2005 and 2010 IRPs, Duke Energy's forecasts for peak demand in 2015 decreased by

20.4%, and during the same time, the projections for 2025 decreased by 2.0%. In comparing Progress Energy's 2005 and 2010 IRPs, the utility showed no change in peak demand forecast for 2015, but it showed a 9.3% decrease in total sales in 2015.

25. As the IRPs show, both Duke Energy and Progress Energy have experienced nearly flat growth in electricity demand for several years. Progress Energy's actual retail sales grew only 0.3% annually from 2000-2009, and Duke Energy's grew only 0.7% annually from 1994-2009. Progress Energy expects its retail sales of electricity to increase by 1.4% annually through its 15-year planning period. Duke Energy is optimistically projecting 1.5% through its 20-year planning horizon.

26. In its 2009 rate case, Docket E-7, Sub 909, Duke Energy adjusted earlier projections to reflect the impact its rate hike would have on customer usage. The revised estimates projected a slightly negative trend in retail sales over the next five years. Notably, these projections were made in early 2009, before the worst impacts of the current economic recession. It seems likely that because of the current economic situation, consumers will remain cautious and growth in sales will remain flat or decrease, especially as any new purchases of appliances, homes, lighting, HVAC systems and turbines will be considerably more energy efficient than current stock.

27. North Carolina should not gamble billions of dollars based on past history and future projections showing in the IRPs, especially when we have better and cheaper alternatives that can be implemented much more quickly and with far less financial risk. Electricity prices have proven to be moderately elastic, customers will cut usage as electricity gets more expensive. It is clear that escalating power bills caused by new nuclear plant construction would result in what is increasingly referred to as

"demand destruction." The costs and risks of the proposed new baseload plants remove them from the least cost mix.

Conclusion.

28. The Commission's responsibility is clear in seeking the "least cost mix" of generation and energy efficiency; the mix focuses on energy efficiency and renewable energy sources and away from "costly overbuilding." The Commission should determine that the proposed new baseload generating units are not needed and existing coal plants can be phased out in a timely manner.

29. As shown above, there are several issues requiring an evidentiary hearing, included but not limited to the escalating costs and lack of need for baseload plants, and especially the proposed nuclear units; the costs and benefits of energy efficiency, renewable energy resources and combined heat and power; and the overly ambitious forecasts of demand growth.

Respectfully submitted, this the 17th day of February 2011.

_______/s/jr______________

John D. Runkle
Attorney at Law
P.O. Box 3793
Chapel Hill, N.C. 27515
919-942-0600 (o&f)
jrunkle@pricecreek.com

CERTIFICATE OF SERVICE

I hereby certify that the persons on the service list have been served this COMMENTS BY NC WARN (E-100, Sub 128) by deposit in the U.S. Mail, postage prepaid, or by email transmission.

This is the 17th day of February 2011.

___________/s/jr________________
Attorney at Law

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[EXPENSIVE PROPOSITION]

New Nuclear Plant Projects Stalled by Market Forces

By MATTHEW L. WALD
THE NEW YORK TIMES

Published: Tuesday, February 8, 2011 at 10:58 p.m.

WASHINGTON | In his State of the Union address, President Barack Obama proposed giving the nuclear construction business a type of help it has never had, a role in a quota for clean energy. But recent setbacks in a hoped-for "nuclear renaissance" raise questions about how much of a role nuclear power can play.

LYNNE SLADKY | ASSOCIATED PRESS (2008)

FLORIDA POWER & LIGHT has plans to add two new nuclear plants at its Turkey Point facility south of Miami. Those would join nuclear reactors already operating there. But the additions remain on the drawing board.

Of four reactor projects identified by the Energy Department in 2009 as the most likely candidates for federal loan guarantees, only two are moving forward. At a third, in Calvert Cliffs, Md., there has been no public sign of progress since the lead partner withdrew in October and the other partner said it would seek a replacement.

And at the fourth, in Texas, a would-be builder has been driven to try something never done before in nuclear construction: finding a buyer for the electricity before the concrete is even poured. Customers are not rushing forward, given the market is awash in generating capacity and an alternative fuel, natural gas, is currently cheap.

"The short answer is, there has to be a market for the power," said John Reed, an investment banker who specializes in nuclear projects. "That's the most immediate hurdle these projects have to get over."

(Both Florida Progress and Florida Power & Light operate nuclear plants in this state and have plans for new ones. But, like others around the country, those additions remain stalled.)

There is a fairly sturdy political consensus in favor of building more reactors. By including nuclear power in a proposed "clean energy standard" shifting the electric system away from conventional coal and gas, whose emissions contribute to global warming, the Obama administration is seeking to stoke such support.

Many Democrats and most Republicans in Congress back nuclear construction, as do local officials in most places where reactors have been proposed.

Sen. Lamar Alexander, R-Tenn., and one of the Senate's strongest proponents of nuclear power, suggests Obama should make building 100 reactors in the next 20 years a national priority, both for energy security and to limit climate-changing emissions.

But for now, he acknowledges, the economics are not in place. "Right now, it's stuck," he said of the planned nuclear revival.

To counter the uncertainties, Alexander and others have arranged substantial help for the industry.

The Nuclear Regulatory Commission has been working for more than 15 years to streamline reactor licensing to cut construction time and to reduce risk. And the 2005 Energy Policy Act provided money for loan guarantees, subsidies for production from the first few reactors and insurance against regulatory delays.

Industry executives say with those changes and the financial help, they had what they needed to build after a gap of three decades. By 2008, the NRC had 15 applications for new nuclear plants in hand and expected 15 more, and it asked Congress for budget increases for personnel to handle the flood.

Across from commission headquarters, in Rockville, Md., workers are now digging a foundation for a $131 million, 14-story office tower for 1,500 employees to handle an anticipated flood of applications. But many of the proposed reactors are fading.

The four projects identified by the Energy Department after the 2005 act as the strongest candidates to share a $18.5 billion pool of loan guarantee money underline the difficulties.

At the Southern Co.'s Vogtle 3 and 4 reactors, near Augusta, Ga., two holes that are each as big as five football fields have been dug for the foundations, and the NRC is expected to grant a license to build and operate the plants this year.

But negotiations on the Calvert Cliffs 3 project in Maryland broke down over what fee the builders should pay to the federal government to compensate the Treasury for the risk it was underwriting. One partner, Constellation Energy of Baltimore, gave up, and the other, Electricite de France, has not found a new investor.

Preliminary work has begun at another site, the Virgil C. Summer 2 and 3 project of South Carolina Electric and Gas, although one of the partners, Santee Cooper, is looking for another company to take over some of its share.

The fate of the fourth, the South Texas Project 3 and 4, has been uncertain since CPS Energy, the municipal utility that serves San Antonio, was spooked by rising cost estimates and decided to bail out. CPS settled with the other partner, NRG of Princeton, for 7.6 percent ownership in exchange for the money it had already invested; for months, NRG has been shopping for partners to replace CPS.

South Texas 3 and 4 and Calvert Cliffs 3 were supposed to help break a 30-year drought and get the ball rolling for construction of dozens of new reactors.

Prospects for weaker ones are fading. In Florida, Progress Energy and Florida Power and Light each wanted to build twin-unit reactors but backed off after the state Public Service Commission ruled last year that the companies could not bill ratepayers for the plants while they were being built.

This story appeared in print on page C6

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Updated Capital Cost Estimates for Electricity Generation Plants

Complete Report with Appendix (pdf)

Release Date: November 2010
Next Release Date: One-Time

The current and future projected cost of new electricity generation capacity is a critical input into the development of energy projections and analyses. The cost of new generating plants plays an important role in determining the mix of capacity additions that will serve growing loads in the future. New plant costs also help to determine how new capacity competes against existing capacity, and the response of the electricity generators to the imposition of environmental controls on conventional pollutants or any limitations on greenhouse gas emissions.

The current and projected future costs of energy-related capital projects, including but not limited to new electric generating plants, have been subject to considerable change in recent years. EIA updates its cost and performance assumptions annually, as part of the development cycle for the *Annual Energy Outlook* (AEO). For the *AEO2011* cycle, EIA commissioned an external consultant to develop current cost estimates for utility-scale electric generating plants.[1] This paper briefly summarizes the design of the project and provides a summary of its main findings, including a comparison of the new estimates to those used in *AEO2010*. The final section discusses how EIA uses information on cost and other factors in modeling technology choice in the electric power sector.

Developing updated estimates: key design considerations

In order to maximize its value to EIA and external energy analysts, the project focused on gathering current information regarding the "overnight"[2] cost for a wide range of generation technologies, while taking care to use a common boundary in the costing exercise across those technologies. The cost estimates for each technology were developed for a generic facility of a specific size and configuration, and assuming a location without unusual constraints or infrastructure needs.

Current information is particularly important during a period when actual and estimated costs have been evolving rapidly, since the use of up-to-date cost estimates for some technologies in conjunction with estimates that are two, three, or even five years old for others can significantly skew the results of modeling and analysis. Where possible, costs estimates were based on information regarding actual or planned projects available to the consultant. When this information was not available, project costs were estimated by using costing models that account for current labor and material rates that would be necessary to complete the construction of a generic facility.

The use of a common boundary for costing is also very important. From experience in reviewing many costing studies for individual technologies, EIA is well aware that differences in practices regarding the inclusion or exclusion of various components of costs can have a large impact on overall cost estimates. This includes the categories of civil and structural costs (e.g., allowance for site preparation, drainage, underground utilities, and buildings), project indirect costs (e.g., a construction contingency), and owners costs (e.g., development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction, and the electrical interconnection costs, including a plant switchyard and tie-in to nearby transmission).

Summary of updated overnight capital costs estimates and comparison to information used in *AEO2010*

Table 1 summarizes the updated cost estimates for the generic utility-scale generation plants represented in EIA's model, including 7 powered by coal, 6 by natural gas, 3 by solar energy, 2 each by wind, hydro, biomass, and geothermal power, and 1 each by uranium and municipal solid waste. For some plant types there are several options shown to better represent the range of plants that might be built and their costs. For example, both single unit and dual unit advanced pulverized coal plants are shown, because many plants include multiple units and the costs associated with the dual unit configuration might better reflect the costs of most plants built.Â Similarly, solar photovoltaic technologies include a relatively small 7 MW system and a much larger 150 MW system, because there is such variance in the sizes of the facilities being considered. The nominal capacity of the generic plants ranges from a 7 megawatt (MW) solar plant to a 2,236 MW advanced dual-unit nuclear plant, reflecting the significant variation in the scale of utility applications. Each technology is characterized by its overnight capital costs, heat rate (where applicable), non-fuel operations and maintenance costs, and, though not shown in Table 1, its environmental characteristics.

Table 2 compares the updated overnight cost estimates to those used as inputs to the *AEO2010*. To facilitate comparisons, both are shown in real year 2010 dollars. Notable changes between the updated estimates and the *AEO2010* values include:

- **Coal & Nuclear:** The updated overnight capital cost estimates for coal and nuclear power plants are 25 to 37 percent above those in *AEO2010*. The higher cost estimates reflect many factors including the overall trend of rising costs of capital intensive technology in the power sector, higher global commodity prices, and the fact that there are relatively few construction firms with the ability to complete complex engineering projects such as a new nuclear or advanced coal power plant. The study assumes cost-sharing agreements between the project owner and the project construction contractors are reflective of those recently observed in the marketplace. As shown in Table 1, dual unit coal and nuclear plants generally have lower overnight costs per kilowatt than single-unit plants, reflecting their ability to take advantage of redundancies and scale economies in onsite infrastructure such as wastewater management and environmental controls to reduce the estimated total per-kilowatt cost of the project.
- **Natural Gas:** The updated cost estimates for natural gas combined cycle and combustion turbines generally remained similar to those of *AEO2010*
- **Solar**: The overnight capital costs for solar thermal and photovoltaic technologies dropped by 10 percent and 25 percent, respectively. The decrease in the cost of photovoltaics was due to the assumption of larger plant capacity and falling component costs.
- **Onshore Wind**: Overnight costs for onshore wind increased by about 21 percent relative to *AEO 2010* assumptions. This is based on a specification for a new, stand-alone wind plant including all owners' costs and may differ from other reported costs in the literature, which are not fully characterized and may include sites that are built along side existing plants (and are thus able to avoid some amount of infrastructure costs).
- **Offshore Wind**: While offshore wind plants have been built in Europe, there have only been proposals in the United States, with final permitting only recently issued on the first of these proposals. The updated costs, some 50 percent higher than *AEO 2010* estimates, are consistent with substantial first-of-a-kind costs that would likely be encountered when building projects in the United States, which largely lacks the unique infrastructure, needed to support this type of construction.
- **Geothermal**: Geothermal costs are highly site-specific, and are represented as such in the AEO estimates. The updated cost estimate is over 50 percent higher than the same site in AEO 2010.
- **Biomass:** Biomass capital costs are largely unchanged from *AEO2010*. However, the technology represented by the costs has changed significantly. Prior estimates were for a highly efficient plant employing gasification and a combined cycle generator; the new estimate is for a significantly less efficient direct combustion boiler. The lower operating efficiency (and therefore higher operating cost) for the biomass plant considered in the updated cost estimate implies a reduced attractiveness of investment in new biomass generation at an overnight cost similar to that for the more efficient biomass plant characterized in *AEO2010.*

While estimates of the current cost of generic electric generation capacity of various types are one key input to EIA's analysis of electricity markets, the evolution of the electricity mix in each of the 22 regions to be modeled in *AEO2011*[3] is also sensitive to many other factors, including the projected evolution of capital costs over the modeling horizon, projected fuel costs, whether wholesale power markets are Â regulated or competitive, the existing generation mix, additional costs associated with environmental control requirements, load growth, and the load shape. Almost all of these factors can vary by region, as do capacity factors for renewable generation, operations and maintenance costs associated with individual plants, and cost multipliers applied to the generic estimates of overnight capital costs outlined in Tables 1 and 2. The next section provides a brief overview of some of the relevant issues, which are described in more detail in the description of the Electric Market Module included in the 2010 edition of the documentation for EIA's National Energy Modeling System.

EIA's analysis of technology choice in the electric power sector

Estimates of the overnight capital cost of generic generating technologies are only the starting point for consideration of the cost of new generating capacity in EIA modeling analyses. EIA also considers regional variation in construction costs, the structure of wholesale power markets that affect financing costs, the length of time required to bring each type of plant into service, and the capacity availability factors for solar and wind generation plants. EIA also accounts for three distinct dynamic forces that drive changes in plant cost over time. One is the projected relationship between rate of inflation for key drivers of plant costs, such as materials and construction costs, and the overall economy-wide rate of inflation. A projected economyâ€“wide inflation rate that exceeds projected inflation for key plant cost drivers results in a projected decline in real (inflation-adjusted) capital costs. Projected capital costs also reflect projected technology progress over time. Learning-by-doing, which allows for additional reductions in projected capital costs as a function of cumulative additions new technologies, has a further effect on technology costs.Â See the *AEO2010* assumptions and model documentation for more details.[4]

Levelized cost is often cited as a convenient summary measure of the overall competiveness of different generating technologies. Levelized cost represents the present value of the total cost of building and operating a generating plant over an assumed economic life, converted to equal annual payments and expressed in terms of real dollars to remove the impact of inflation. Levelized costs, which reflect overnight capital cost, fuel cost, fixed and variable O&M cost, are a useful indicator of the competitiveness of different generation technologies. For technologies such as solar and wind generation that have no fuel costs and relatively small O&M costs, levelized cost changes in rough proportion to the estimated overnight capital cost of generation capacity. For technologies with significant fuel cost, both fuel cost and overnight cost estimates significantly affect levelized cost. Thus, while Table 2 shows little change between the updated capital cost estimates for natural gas combined cycle plants and those used in *AEO2010*, improved supply prospects for natural gas that will be incorporated in *AEO2011* result in lower projected prices that in turn lower the levelized cost of gas-fired generation and improve the attractiveness of operating and adding gas-fired generation technologies.

It is important to note, however, that actual investment decisions are affected by numerous factors other than levelized costs. The ***projected utilization rate***, which depends on the load shape and the existing resource mix in an area where additional capacity is needed, is one such factor. The ***existing resource mix*** in a region can directly affect the economic viability of a new investment through its effect on the economics surrounding the displacement of existing resources. For example, a wind resource that would primarily back out existing natural gas generation will generally have a higher value than one that would back out existing coal generation under fuel price conditions where the variable cost of operating existing gas-fired plants exceeds that of operating existing coal-fired plants.

A related factor is the ***capacity value****,* which depends on both the existing capacity mix and load characteristics in a region. Since load must be balanced on a continuous basis, units whose output can be varied to follow demand generally have more value to a system than less flexible units or those whose operation is tied to the availability of an intermittent resource. Policy-related factors, such as investment or production tax credits for specified generation sources, can also impact investment decisions. Finally, although levelized cost calculations are generally made using an assumed set of capital and operating costs, the inherent uncertainty about future fuel prices and future policies, may cause plant owners or investors who finance plants to place a value on ***portfolio diversification****.* EIA considers all of these factors in its analyses of technology choice in the electricity sector.

In sum, while overnight cost estimates are important inputs for EIA modelers and other analysts, they are not the sole driver of the choice among electric generation technologies. Users interested in additional details regarding these updated cost estimates should review the consultant study prepared by R.W. Beck for EIA in the appendix of the compete report linked to above.

Footnotes

1 EIA's electricity modeling includes both combined heat and power (CHP) technologies as well as a variety of distributed generation technologies, but those technologies were not addressed in the study, which focused on technologies within the electric power sector.

2 "Overnight cost" is an estimate of the cost at which a plant could be constructed assuming that the entire process from planning through completion could be accomplished in a single day. This concept is useful to avoid any impact of financing issues and assumptions on estimated costs. Starting from overnight cost estimates, EIA's electricity modeling explicitly takes account of the time required to bring each generation technology online and the costs of financing construction in the period before a plant becomes operational.

3 In *AEO2010* and prior editions, the continental U.S., excluding Alaska, was divided in 13 regions for purposes of electricity modeling. The 22 region model that will be used starting with *AEO2011* will allow for better representation of policy boundaries and market structure at the State level.

4 Assumptions and model documentation for the *Annual Energy Outlook 2010* are available at http://www.eia.gov/oiaf/aeo/index.html.

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Review of ACEEE's North Carolina Study Electricity Results

Presented to the Energy Policy Council
April 29th, 2010

R. Neal Elliott
Maggie Eldridge

Presentation Summary

- Meta-Review
- ACEEE Medium Case Scenario
- EERS Details
- Review of EPRI Study
- State Best Practices

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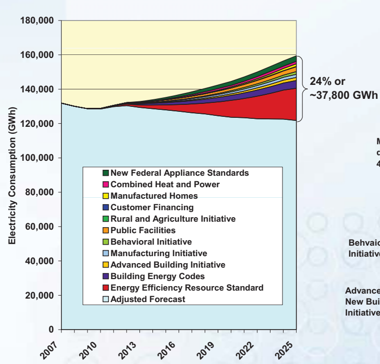
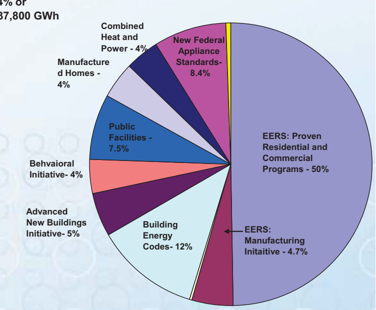
Meta Review of EE Market Potential Studies

North Carolina & South Carolina Studies	Study time period	Savings (GWh)	Savings (%)	Avg. Annual Savings (%)
GDS Associates: North Carolina, 2006 (<$0.05/kWh)	2008-2017, 10 years	25,132	14%	1.4%
GDS Associates: North Carolina, 2006 (Achievable)	2008-2017, 10 years	36,235	20%	2.0%
Appalachian State University: North Carolina, 2007	2007-2020, 13 years	29,235	16%	1.2%
GDS Associates: South Carolina, 2007	2008-2017, 10 years	4,008	20%	2.0%
Forefront Economics: Duke Energy Carolinas - South Carolina, 2007	2007-2026, 20 years	3,576	16%	0.8%
			Average:	*1.5%*
Regional Studies				
SEEA Energy Efficiency in Appalachia	2010-2030, 20 years	23.2 quads, total	33%	1.6%
WRI Southeast Energy Opportunities	2009-2025, 17 years	244,000	20%	1.2%
			Average:	*1.4%*
National Studies				
McKinsey and Company	2008-2020, 13 years	9.1 quads	23%	1.8%
ACEEE 2008 Meta-Review of state and regional elec. studies - achievable	average 12 years	NA	NA	1.5%
			Average:	*1.6%*

Electricity Savings from Policies: Medium Case Scenario – 24% by 2025



2025 Savings by Sector



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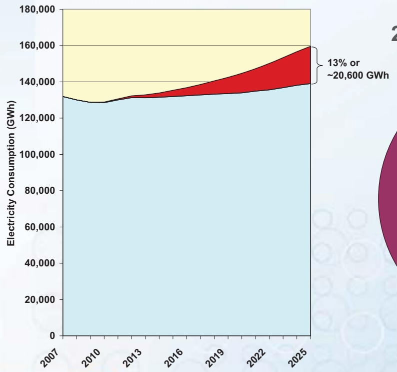
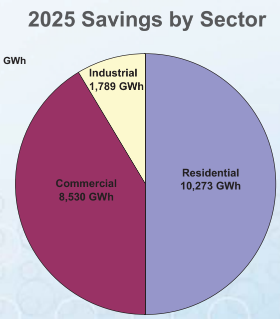
Closer Look at an EERS in Medium Case Scenario





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Closer Look at an EERS in Medium Case Scenario

- Total annual 13% savings of projected 2025 sales
- Achieved through annual incremental electricity savings utility targets: 1.0% /yr by 2015; 1.5% by 2019; 1.75% by 2022; and 2% by 2025
- Savings targets through 2015 consistent w/ Duke Save-a-Watt agreement
- Manufacturing Initiative achieves savings for industrial customer class that apply
- Additional opportunities to pursue savings from:
  - building energy codes compliance
  - state and local public facilities
  - behavioral initiative
  - CHP

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EERS by year – GWh

	2010	**2011**	**2012**	**2013**
Forecast	128,813	130,557	132,272	132,825
Annual Targets	0.30%	*0.30%*	*0.50%*	*0.75%*
Adj. Forecast for EERS and Fed. App. Stdrds	128,482	*130,017*	*131,166*	*130,790*
Total Annual Savings from EERS	330	538	974	1,615

2014	**2015**	**2016**	**2017**	**2018**	**2019**
133,867	135,304	136,789	138,547	140,517	142,534
0.75%	*1.0%*	*1.0%*	*1.25%*	*1.25%*	*1.50%*
130,846	*130,917*	*131,025*	*131,165*	*131,429*	*131,422*
2,352	3,446	4,494	5,780	7,248	9,033

2020	**2021**	**2022**	**2023**	**2024**	**2025**
144,635	147,253	150,157	153,308	156,593	159,583
1.50%	*1.50%*	*1.75%*	*1.75%*	*1.75%*	*2.0%*
131,600	*132,409*	*132,914*	*133,953*	*135,091*	*135,808*
10,740	12,357	14,575	16,515	18,490	20,591

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Analysis of National EE study by the Electric Power Research Institute (EPRI), 2009

- Joint comments prepared by ACEEE, Alliance to Save Energy, NRDC, and Energy Center of Wisconsin: EPRI study underestimates EE potential
- Estimates 5-10% potential in 2020 (0.4-0.85% per year) and 8-11% in 2030 (0.37-0.51% per year)
- Savings are based on energy-saving technologies (e.g. lamps or air conditioners), but not many energy-efficient practices (e.g. building systems design or industrial processes)
- Report assumes programs do not induce early replacement of technologies before end of useful life

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Energy Efficiency Resource Standard: Decoupling and Performance Incentives

- With increasing EE goals & budgets, need to develop & apply new utility regulatory business models
- Rate structures & public benefits fees only "recover" program costs – don't address "lost revenues" or investment earnings.
- "Decoupling" revenues from energy sales removes disincentive for achieving energy savings from programs—growing number of states doing this.
- "Performance" or "shareholder" incentives provide positive financial earnings on EE program costs and/or investments—growing number of states also doing this

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Best Practices in Leading States
(York et al 2009)

- **Energy Efficiency Cost Recovery** –14 leading states have some type of well-established, practical & substantial utility rate funding mechanism for EE program cost recovery.
- **Shareholder Incentives** – utilities primary administrator of EE programs in 9 of 14 states. Seven of 9 feature some type of "shareholder incentive" tied to EE performance.
- **Other Performance Incentives** –Other five states have the EE programs administered by govt. or "3rd party non-profit organizations", so shareholder incentives are not applicable, but 2 have performance incentives for the administrator.

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Review of Best Practices
Annual spending and savings by energy efficiency programs in leading states (2007 data—excludes load mgmt)

State (ACEEE 2008 State Scorecard Rank—Utilities Policies only)	Total Program Spending	Spending as % of Total Revenues	Annual Savings	Savings as % total energy sales*
	$ million	%	MWh	%
Connecticut (2)	$98.2	2.1%	355,000	1.3%
Vermont (1)	$23.7	3.5%	105,243	1.8%
Massachusetts (6- tie)	$120.2	1.4%	489,622	0.9%
Oregon (4 – tie)	$69.1	2.2%	437,494	0.9%
Washington (8)	$126.7	2.4%	635,062	0.7%
California (3)	$733.0	2.1%	3,816,000	1.6%
Iowa (9)	$56.5	1.8%	322,177	0.7%
New York (6 – tie)	$241.5	1.1%	823,837**	0.6%
Minnesota (4 - tie)	$91.2	1.9%	463,543	0.7%
Wisconsin (10)	$80.6	1.4%	467,725	0.7%

* State avg.—individual utility savings may be higher
**2006 savings data for NY

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Energy Efficiency Program Costs
(Friedrich et al 2009)

Cost of Saved Energy (CSE) from the Utility Cost Perspective

	Mean	Median	Range
Electricity Programs (per kWh)	$0.025	$0.027	$0.016 - $0.033
Natural Gas Programs (per therm)	$0.37	$0.33	$0.27 - $0.55

- Means are calculated from the averages for each state for 2002 – 2007 programs
- No correlation found between increasing targets & increasing cost of saved energy

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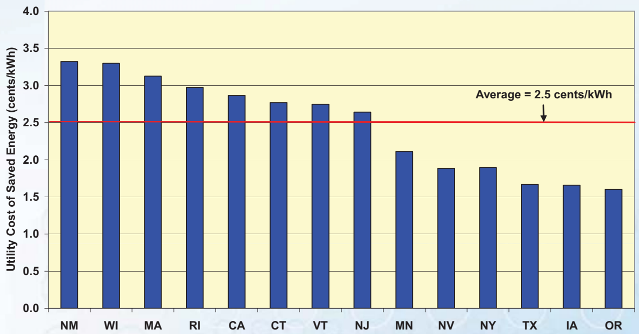
Average State Cost of Saved Electricity



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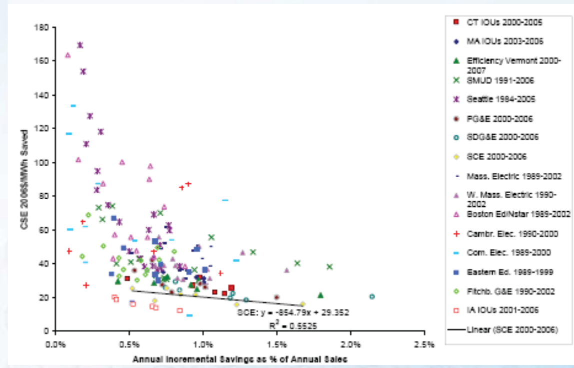
Utility Cost of Saved Energy vs. Incremental Annual Savings as % of Sales



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Source: Takahashi and Nichols 2008

EE as a Resource:
PJM Forward capacity market

- EE resources compete with other resources to set market clearing price
- Example from New England: First auction (Feb 08) included 2500 MWs of DR and EE
- Provides grid reliability because EE resources are "committed" & no fuel supply issues
- Allows EE to participate for life of measure – essential to 3rd-party aggregation of small EE resources
- Rigorous M&V standards establish EE value
- In 2012/2013 RPM auction, EE cleared ~550 MW
- With no EE/DR resources, market clearing price would be about 1.5 – 2 x higher (11 times higher in RTO)

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PJM DR & EE Offer Impact

	Actual Auction Results		Two Thirds of Actual DR or EE Offers		One Third of Actual DR or EE Offers		No DR or EE Offers	
LDA	Clearing Prices ($/MW-day)	Cleared UCAP (MW)	Clearing Prices ($/MW-day)	Cleared UCAP (MW)	Clearing Prices ($/MW-day)	Cleared UCAP (MW)	Clearing Prices ($/MW-day)	Cleared UCAP (MW)
DPL South	$222.30	1,241.5	$222.30	1,241.5	$222.30	1,307.0	$264.66	1,434.3
PSEG North	$185.00	3,521.9	$178.26	3,396.8	$222.30	3,699.6	$264.66	3,676.8
EMAAC	$139.73	31,080.2	$178.26	30,865.8	$222.30	30,701.3	$264.66	30,248.2
MAAC	$133.37	65,452.4	$178.26	64,643.6	$222.30	63,404.1	$264.66	61,823.8
RTO	$16.46	136,143.5	$19.31	136,143.5	$51.53	136,143.5	$178.78	133,568.2

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Duke Energy in Ohio

- Ohio SB 221 requires 0.3% savings in 2009, ramping up per year to 0.5%, 0.7%, 0.8%, 0.9%, to 1% /yr by 2014 through 2018; 2% in 2019 through 2025
- Duke Energy Ohio, in its Electric Security Plan filing, noted its plans to meet the statutory energy efficiency mandates

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Conclusions

- Meta-review of EE market potential studies for the state, region, & nation provide strong basis for efficiency EERS targets in ACEEE study
- Energy efficiency can be a reliable, cost-effective resource for utility planning in North Carolina
- Performance incentives will support the continued success of utilities in meeting efficiency targets

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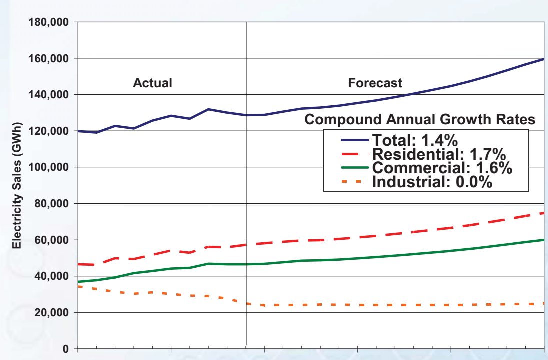
Extra Slides

Statewide Electricity Sales Forecast



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Electricity Sales Forecast Assumptions

- Compiled from 2009 IRP utility filings; constrained to North Carolina sales only
- Takes into account savings from *EISA 2007* federal efficiency standards (per Duke Energy assumption and U.S. Energy Information Administration's *2009 Annual Energy Outlook)*

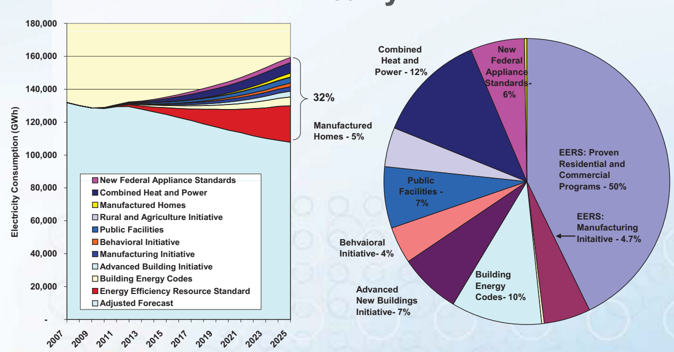
Federal Appliance Efficiency Standards

- EISA 2007 standards – estimated to meet about 3,000 GWh, or 2% of North Carolina's electricity needs in 2025 (or 0.13% per year)
- About 20 new and updated federal efficiency standards are pending DOE rulemakings by 2013
- Could achieve an additional 4% of NC's electricity needs by 2025

Remarks on meta-review

- North Carolina studies were completed prior to 2007 EISA—do not reflect savings that will accrue from federal standards
- Each study examined different sets of measures and uses different set of assumptions
- Many emerging technologies not included
- Based on past experience, should be viewed as a lower bound on savings potential

Electricity Savings from Policies: High Case Scenario – 32% by 2025



Closer Look at EERS in High Case

- Total annual 16% savings by 2025
- Annual targets: 1.0% /yr by 2013; 1.5% by 2016; 1.75% by 2018; and 2% per year by 2022
- Manufacturing Initiative achieves savings for industrial customer class
- Additional opportunities to pursue savings from:
  - building energy codes compliance
  - state and local public facilities
  - behavioral initiative
  - CHP

Targets should be increased to reflect these increased savings potential

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