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NOV 23 2011

PUBLIC SERVICE
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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE 2011 JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	))))	**CASE NO. 2011-00140**

COMMENTS OF INTERVENORS NATURAL RESOURCES DEFENSE COUNCIL AND SIERRA CLUB ON THE 2011 JOINT INTEGRATED RESOURCE PLAN OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC

Intervenors Natural Resources Defense Council and Sierra Club (collectively, "Environmental Groups") hereby comment on Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "Companies") 2011 Joint Integrated Resource Plan ("IRP"). The Environmental Groups are gladdened that the IRP calls for the retirement of the Companies' aging and dirty Cane Run, Green River, and Tyrone coal-fired electric generating units, and for some increase in the demand side management ("DSM") and energy efficiency ("EE") efforts of the Companies. However, the IRP includes a number of flaws that result in the plan failing to set forth the lowest cost approach for the Companies to meet their future energy needs. Specific shortcomings in the IRP include:

- A failure to provide a meaningful analysis sensitivity analysis for the load growth projections;
- Selection of an excessive reserve margin;
- A need to enhance the demand side management programs so as to more fully capture all cost-effective means for reducing demand growth;
- Reliance on an unsupported assumption that there will be zero future costs related to carbon dioxide ("CO2"), rather than evaluating a range of potential CO2 costs;
- An inadequate assessment of the full set of capital, environmental, fuel, and operating and maintenance costs facing the Companies aging coal-fired electric generating units; and
- Failure to factor in and account for uncertainty in energy planning.

A thorough and well-reasoned IRP is especially important now as it is a critical time for the Companies. A number of the Companies' coal-fired electric generating units have reached or exceeded their expected service lives, raising the need for major capital investments if such units are to continue to operate. In addition, existing and expected environmental standards will finally require the Companies (and utilities throughout the country) to either install pollution controls on coal units or to retire such units. Technological advances and changes in market conditions have made a larger suite of both supply- and demand-side options available for the Companies to satisfy their customers' needs. And growing awareness of the economic, public health, and environmental impacts of energy production have increased the importance of the pursuit of energy efficiency and renewable energy resources from both a cost and environmental perspective. In short, the Companies face a new reality involving a growing set of costs to its existing generation fleet, an expanding set of options for how to service its customers, and an increasingly complex set of factors relevant to identifying the lowest cost mix of supply- and demand-side resources for meetings its customers' needs. The Environmental Groups present these comments on the IRP in the spirit of helping the Companies and the Commission pursue a clean energy future that benefits the ratepayers' pocketbooks and the health of all Kentuckians.

I. IRP Standards

The IRP process in Kentucky is governed by 807 K.A.R 5:058, which requires the Companies to submit every three years a plan that discusses historical and projected demand, resource options for satisfying that demand, and the financial and operating performance of the Companies' system. 807 K.A.R. 5:058 Section 1(2). Core elements of the filing include:

- A base load forecast the Companies consider "most likely to occur and, to the extent available, alternate forecasts representing lower and upper ranges of expected future growth of the load on its system" 807 K.A.R. 5:058 Section 7(3).
- The Companies' "resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost." 807 K.A.R. 5:058 Section 8(1).
- The revenue requirements and average system rates resulting from the plan set forth in the IRP. 807 K.A.R. 5:058 Section 9.

As the Commission Staff have stated:

> The goal of the Commission in establishing the IRP process was to ensure that all reasonable options for the future supply of electricity were being examined and pursued, and that ratepayers were being provided a reliable supply of electricity at the lowest possible cost.[1]

It is with that intent in mind that the Environmental Groups offer the following comments.

[1] Kentucky PSC, Staff Report on the 2009 Integrated Resource Plan of Kentucky Power Company, Case No. 2009-00339 (Mar. 2011).

II. The Companies' Load Growth Projections Fail to Include A Meaningful Sensitivity Analysis.

The first fundamental step in any IRP process is to reasonably project the amount of energy demand that the Companies will need to satisfy over the planning period. The Companies carried out an analysis of total electricity sales and peak demand over the 15 year planning period and concluded that while demand has dropped significantly due to the 2008 recession it will recover and grow at a faster rate than was predicted by the Companies in their 2008 IRP. For total electricity sales, the Companies predict levels for 2011 to 2015 will be 5.8% lower than was predicted in the 2008 IRP. (IRP at 6-3). The Companies also, however, project a higher annual growth rate of 1.6% from 2011 to 2015 (compared to 1% in the 2008 IRP) and 1.5% for 2011 to 2025 (compared to 1.2% in the 2008 IRP). (*Id.*) As a result, total energy demand is projected to be 23.2% higher in 2025 than in 2011. Similarly, peak demand in 2011 to 2015 is projected to be 5% lower than was predicted in the 2008 IRP. (*Id.* at 6-5). The Companies then project that peak demand will grow at 1.7% through 2025, rather than the 1.3% level identified in the 2008 IRP. (*Id.*). As a result, peak energy demand is projected to be 28.4% higher in 2025 than in 2011.

While the Companies have apparently assumed a full recovery from the 2008 recession, they have not provided any explanation for why they expect total electricity sales and peak energy demand to grow at a higher annual rate than they projected in the 2008 IRP. This higher projected growth rate is especially surprising given that the energy efficiency provisions of the Energy Independence and Security Act of 2007 (EISA") and the American Recovery and Reinvestment Act of 2009 ("ARRA") were supposedly incorporated into the demand growth projections. The ARRA programs alone are projected to reduce residential demand by 0.2% per year every year through 2020.[2] The lighting efficiency standards in the EISA are expected to reduce residential energy use by 1.5 to 2.5% in 2012-2014.[3] And various provisions of EISA and ARRA were projected by Itron to reduce the projected increase in commercial sector electricity use from the 2.1% annual increase projected in 2008 for 2009 to 2019 to only a 1.6% annual increase.[4] In light of these reductions and the continued economic difficulties facing Kentucky, it would appear that the Companies' estimate of increased annual electricity demand growth as compared to the 2008 IRP is overstated.

The Companies do acknowledge that "within each forecast cycle, there is uncertainty in the forecast values of the independent variables." (IRP at 7-25). This uncertainty is especially acute for peak demand growth, with regards to which the Companies note "significant uncertainty about the rate of growth of peak demand and capacity additions." (*Id.* at 6-26). For example, Cambridge Energy Research Associates ("CERA") has projected a nationwide peak

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[2] Itron, 2009 Residential Statistically Adjusted End-Use (SAE) Spreadsheets – ARRA Stimulus Forecast, Attachment to Companies' Resp. to NRDC-SC Interrogatory No. 2.

[3] Itron, 2009 Residential SAE Update at 1, Attachment to Companies' Resp. to NRDC-SC Interrogatory No. 1.

[4] Itron, 2009 Commercial SAE Update, at 13, Attachment to Companies' Resp. to NRDC-SC Interrogatory No. 1.

demand growth increase of 1.9% per year from 2010 to 2015, while the U.S. Department of Energy's Energy Information Administration projects only 0.1% peak demand growth. (*Id.*).

Robust utility planning addresses such uncertainty through the use of sensitivity analyses that measure the impact of a range of different input scenarios combined with an assignment of probabilities to each scenario. So, for example, with regards to load growth, a sensitivity analysis would evaluate how different assumptions regarding economic growth, population growth, or weather would impact the projected change in electricity demand growth over the planning period. Utilities would then assign different probabilities to each set of assumptions in order to conclude which scenario is most likely.

The Companies purport to have undertaken a sensitivity analysis with regards to electricity demand growth, but it was not a meaningful analysis. Instead of testing a range of input assumptions in order to identify different projected demand growth trajectories, the Companies generated a "high case" by assuming that demand in 2011 would be 4% higher than projected, and a "low case" by assuming that demand in 2011 would be 4% lower than projected. (IRP at 7-26). The Companies then assumed that energy sales and peak demand will grow at the exact same annual rates as were used in identifying the "base case." (*Id.*). In other words, the only sensitivity that was added into the evaluation concerned whether the demand would be higher or lower than expected. No sensitivity analysis was presented regarding the rate of energy demand growth over the planning period, which is the critical factor in determining what level of energy demand the Companies will need to serve over the next fifteen years.

The Companies acknowledge that "alternative load growth scenarios may have a significant impact on the selection of an optimal technology, type, and size." (IRP at 5-13). For example, a lower rate of growth could delay, shrink, or eliminate the need for new generating capacity, thereby saving ratepayers money. Conversely, a higher growth rate could lead to an increased need for additional generating capacity. Carrying out sensitivity analyses that look at the range of potential demand growth trajectories is critical to ensuring that the optimal combination of energy resources is selected.

III. The Companies Have Selected an Excessive Reserve Margin

The Companies appear to have overstated the amount of capacity they need by selecting an excessive 16% reserve margin for the system. A reserve margin is the amount of excess capacity a utility carries in order to minimize the likelihood of reliability events. Relying on an analysis by Astrape Consulting titled LG&E and KU 2011 Reserve Margin Study ("RMS"),[5] the Companies contend that the current 14% reserve margin should be increased to 16% because that latter figure purportedly represents the level that optimally balances the cost of holding reserve energy resources with the risk and impact of a reliability event. In other words, the RMS

[5] Astrape Consulting, LG&E and KU 2011 Reserve Margin Study (April 8, 2011) (hereinafter "RMS"). The RMS was filed with the Commission by the Companies as Ex. CRS-3 to the Rebuttal Testimony of Charles R. Schram in PSC Case Nos. 2011-00161 and 00162.

focused on the "estimated total costs and risks to customers" of various reserve margins,[6] rather than the traditional approach of identifying the minimum level of generation planning reserve margin needed to maintain electric system reliability. Regardless of the validity of this non-traditional approach, the 16% figure is higher than is necessary or beneficial to ratepayers.

One way that the RMS overstates the appropriate reserve margin is by explicitly modeling two types of load forecast uncertainty rather than just one. In particular, the RMS incorporates weather uncertainty and economic uncertainty, both based on historical loads. This increases the amount of uncertainty being modeled and raises questions about the possibility of historical uncertainty being duplicated by the multiple methods used in the RMS. Load forecast uncertainty due to economic uncertainty results in a peak load, in the most extreme case, that has only a 2.25% probability of occurring. Given that most economic uncertainty is currently on the downside, with lower than expected loads, this seems extreme and acts to improperly increase the apparently optimal reserve margin.

More traditional loss-of-load-probability ("LOLP") planning uses a load forecast that has a certain overall confidence level, such as a "50/50" forecast that has a 50% chance of being exceeded in any one year. Some Regional Transmission Organizations use a 90/10 load forecast, in which the forecast load has a 10% chance of being exceeded in any one year, for some system planning purposes. But, the 50/50 forecast is still widely used for generation adequacy purposes.[7] In either event, a specific overall confidence level applies to the loads being studied. This compares to the RMS which reflects economic uncertainty such that the worst case load has less than 2.25% chance of being exceeded.[8] And this is before weather-driven load forecast uncertainty is taken into account. While load forecast uncertainty should be considered, the method used in the RMS departs from the planning basis on which our electric utility system has been developed and operated and acts to increase what the planning reserve margin should be relative to traditional LOLP study methods. As such, it should be strictly scrutinized.

A second problem with the RMS is that it overestimates the level of reserve margin needed to achieve a loss of load probability ("LOLP") of 0.1, which is the equivalent of 1 day of lost energy in ten years. The appendix to the reserve margin study contends that a 20% reserve margin is needed to reduce the LOLP to 0.1, and that the LOLP would be at 0.2 with a reserve margin of 16%.[9] But other utilities have found that a far lower margin than 20% is needed to get the LOLP down to 0.1. For example, NERC has reported that the Florida Reliability Coordinating Council found that a 15% reserve margin would achieve a LOLP of 0.1.[10] Similarly, PacificCorp recently determined that a 14.8% reserve margin was sufficient to achieve a 0.1 LOLP.[11] The LOLP at various reserve margin rates represents the probability that the

[6] RMS at 2.
[7] PJM uses a 50/50 load forecast in its generation adequacy determination.
[8] RMS at 14.
[9] RMS at Appendix A.
[10] NERC, 2011 Summer Reliability Assessment (May 2011), at 47, *available at* http://www.nerc.com/files/2011%20Summer%20Reliability%20Assessment_FINAL.pdf.
[11] PacifiCorp, Stochastic Loss of Load Study for the 2011 Integrated Resource Plan (Nov. 18, 2010), at 9-10, *available at*

system is likely to experience a shortage of generation over a given planning year. Therefore, overstating the LOLP at a particular reserve margin rate would suggest a higher margin than is cost effective.

The RMS is also flawed because it does not appear to give any credit to demand side resources ("DSR"). The NERC 2011 Summer Reliability Assessment[12] documents how NERC has enhanced its method of calculating reserve margin to account for controllable DSR, which acts similar to generation in its ability to "serve" load. Rather than being subtracted from capacity and load, as was previously the case, now controllable DSR MWs are now added to generating capacity, which will tend to increase the calculated reserve margin in 2011 and later years, all else held equal. DSR should be factored into the Companies' reserve margin analysis.

Finally, the Companies' reserve margin study appears to omit consideration of the Contingency Reserve Sharing Group ("CRSG") that the Companies have joined with the Tennessee Valley Authority and East Kentucky Power Company.[13] The members of the CRSG share 1,347MW of contingency reserves, which enables each individual utility to reduce the amount of contingency reserves it carries on its own.[14] Other utilities have assumed that participation in similar reserve sharing groups reduces the reserve margin that a single utility needs by as much as 1.5%.[15] The CRSG should similarly be factored into further analysis of the reserve margin for the Companies.

IV. The Companies Should Enhance Demand Side Management Programs and Adjust the Underlying Load Forecasts for the IRP Accordingly.

The best energy resource from both an economic and environmental perspective is demand side management ("DSM"), which uses energy efficiency and demand response programs to reduce the total amount of electricity that a utility needs to produce in order to satisfy its customers' needs. Experience throughout the country shows that well-designed and implemented DSM programs can reduce energy demand by 1% to 2% per year at a significantly lower cost than it takes to produce that same amount of energy. As such, any energy planning process that seeks to achieve the lowest cost energy portfolio should prioritize the implementation of all cost effective DSM.

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http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/PAC_2011IRP_LossOfLoadStudy_11-18-10.pdf

[12] NERC Reliability Assessment at 3; NERC, Recommendations for the Treatment of Controllable Capacity Demand Response Programs in Reserve Margin Calculations (June 1, 2010), available at http://www.nerc.com/docs/pc/ris/RIS_Report_on_Reserve_Margin_Treatment_of_CCDR_%2006.01.10.pdf.

[13] Contingency Reserve Sharing Group, Certificate of Deliverability, available at http://www.oatioasis.com/EKPC/EKPCdocs/TEE_CRSG_Certification_of_Deliverability_04302010.pdf

[14] Companies' Resp. to Staff Interrogatory No. 10.

[15] PacifiCorp at 10; Ventyx, Analysis of "Loss of Load Probability" (LOLP) at Various Planning Reserve Margins (Dec. 1, 2008).

To their credit, the Companies have, in a separate filing (PSC Case No. 2011-00134) recently approved by the Commission, sought to expand their DSM programs.[16] The Companies' existing DSM programs have achieved 182 MW of peak demand reduction through 2010. The continuation of those programs and addition of new programs approved in Case No. 2011-00134 are expected to lead to additional peak demand reduction of 309 MW over the next seven years, for a total peak demand reduction of 491 MW by the end of 2017. (IRP at 6-24). The IRP then assumes another 58MW of peak demand savings from DSM programs each year through 2025, for a total of 838.7MW of peak demand reduction. (IRP at 8-75). This equates to a total peak energy demand savings of 9.36% by the end of 2025, which is an average reduction of approximate 0.52% of peak demand per year since the DSM programs started in 2008. With regards to total energy sales, the Companies estimate that their DSM programs will lead to a 1,950GWh reduction by the end of 2025. (IRP at 8-74). This equates to a 4.6% reduction in total energy sales by the end of 2025, which is an average energy savings of only 0.25% per year.

While these DSM programs are a good start, the Companies can cost- effectively achieve far more reduced demand. The Companies' own filings show that the proposed DSM programs' expected benefits far outweigh their costs, which provides strong evidence that there are significant opportunities for additional energy savings through cost-effective DSM programs. For example, the IRP estimates the existing and new DSM programs from 2011 through 2017 will cost $261 million, while the net present value of those programs is estimated at $864 million. (IRP at 8-76). That 3.3 to 1 benefit-cost ratio suggests that there is a lot of additional energy savings that the Companies could achiev through DSM programs with a positive benefit-cost ratio.

That the Companies can and should pursue far more DSM is also seen through the DSM Program Review that was carried out by ICF International.[17] Among other things, the DSM Review evaluated the Companies' DSM programs in terms of the four cost-effectiveness tests set forth in the California Standard Practice Manual. (IRP at 8-109 to 8-111). The Companies' DSM programs have significant positive net economic benefits under the Participant Test (8.24), Utility Cost Test (3.39), and Total Resource Cost Test (3.01). The high Utility Cost Test result indicates that there is significant opportunity to cost effectively increase the DSM incentives offered in order to increase participation in energy saving programs. And the high Total Resource Cost score indicates that the Companies could expand the DSM programs to go after much deeper energy savings, while still staying cost effective and delivering net benefits to the service territory.

ICF did find that the DSM programs had a marginally negative Ratepayer Impact score of 0.82. (IRP at 8-111). While the Companies should not use the Ratepayer Impact test alone to

[16] *See* In re Joint Application of Louisville Gas & Electric and Kentucky Utilities Company for Review, Modification, and Continuation of Existing, and Addition of New Demand Side Management and Energy Efficiency Programs, PSC Case No. 2011-00134.

[17] ICF International, Louisville Gas and Electric Company / Kentucky Utilities Company – DSM Program Review (Mar. 18, 2011). The ICF Report was filed with the Commission as Exhibit 10 to the Companies' Demand Side Management and Energy Efficiency Program Plan filing in PSC Case No. 2011-00134.

evaluate the cost effectiveness of DSM because, as the ICF analysis noted, that test has "serious disadvantages" stemming from the fact that it likely provides the least certain results of any of the cost effectiveness tests.[18] While the Ratepayer Impact score should play a role in determining which specific DSM programs to pursue and how to design those programs to properly balance the costs and benefits for participants, utilities, and non-participants, the appropriate overall level of DSM is most appropriately evaluated by considering the results of all of the cost-effectiveness tests.[19] Doing so here reveals a substantial benefit from the Companies' existing and recently-approved DSM programs, and the opportunity to cost effectively reduce significantly more demand through further DSM efforts.

The 0.52% per year demand reduction from the Companies' DSM programs also falls far short of the energy saving goals targeted for Kentucky. In particular, Kentucky Governor Steven L. Beshear has called for the establishment of an Energy Efficiency Resource Standard that would seek to reduce energy consumption by at least 16 percent below projected 2025 levels, for a savings rate of 1.13% per year.[20] While the Governor's goal is not a binding requirement yet, it provides additional evidence that the Companies could achieve far more cost effective demand reduction through enhanced DSM efforts.

The projected energy savings from the Companies' DSM programs also falls far below the energy saving requirements established in many other states. For example, at least eleven states now have policies requiring more than 10% cumulative annual energy savings by 2020 through DSM policies.[21] Most states are meeting their energy saving goals, and nine states achieved energy savings of more than 1.2% in 2009 or 2010.[22] Ohio recently passed legislation requiring 22% energy savings by 2025, starting at 0.3% annual savings in 2009, ramping up to 1% annual savings by 2014, and 2% in 2019.[23]

Based on all of the above, the Companies should evaluate and implement a much more robust DSM program that would achieve significantly higher annual reductions of peak energy demand and total energy sales. The best way to evaluate the level of DSM that should be pursued is to allow DSM programs to compete against supply side resources on equal footing in any energy planning modeling undertaken by the Companies. In addition, the Commission should follow ICF's recommendation and call on the Companies to conduct an energy efficiency potential study, which would help the Companies determine how much energy efficiency is available in their service territory and at what cost it is available. American Electric Power

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[18] ICF Plan at 20.
[19] National Action Plan for Energy Efficiency (2008). *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers.* Energy and Environmental Economics, Inc. and Regulatory Assistance Project, at p. 3-1, *available at* http://www.epa.gov/cleanenergy/documents/suca/cost-effectiveness.pdf
[20] Governor Steven L. Beshear, 2008, *Intelligent Energy Choices for Kentucky's Future: Kentucky's 7-Point Strategy for Energy Independence*, available at http://energy.ky.gov/resources/Pages/EnergyPlan.aspx
[21] American Council for an Energy-Efficient Economy, Energy Efficient Resource Standards: A Progress Report on State Experience (June 2011), at 8-9.
[22] *Id.* at 9.
[23] Ohio Revised Code 4928.66.

recently completed such a study in Ohio and concluded that utilities could realistically reduce load by more than 20% by 2028 with cost effective energy efficiency.

For purposes of the present IRP, the Companies should, at a minimum, assess the impact of achieving higher levels of energy savings and peak demand reduction through the use of DSM. The Environmental Groups recommend that the Companies double their DSM related energy savings to 1% of sales for each of the next three years, and to increase the level to 2% per year thereafter. Such energy savings would save ratepayers money not only by reducing the amount of electricity they need to purchase, but also by enabling the Companies to reduce the amount of new or retrofitted power generation capacity that it pursues.

V. The Companies Should Factor In the Likelihood of a Cost on CO2 Emissions

A serious shortcoming in the Companies' IRP is a failure to assume any cost related to the emission of carbon dioxide ("CO2"). The Companies currently generate 97% of their electricity from coal, which is the most carbon-intensive energy source there is. Even after the coal unit retirements and natural gas proposals included in this IRP, the Companies would still be generating approximately 90% of their electricity from coal. As such, the Companies and their ratepayers have significant exposure in the event that a price is placed on CO2 emissions or that environmental standards require reductions in those emissions. Given the significant environmental impacts that result from CO2 emissions, it remains very likely that the Companies will be required at some time during the planning horizon under consideration in this IRP to either reduce their CO2 emissions or pay a fee for such emissions. As such, it would be in the best interest of the ratepayers for the Companies to factor that likelihood into their planning and to begin taking cost effective steps now to reduce such emissions.

A regulatory cost related to CO2 emissions is likely to come in one of two forms. First, there could be a federal price on CO2 as part of a cap-and-trade type system in which overall CO2 emissions are capped and then major sources of CO2 emissions are able to purchase and trade CO2 pollution allowances. Second, U.S. EPA is in the process of promulgating greenhouse gas New Source Performance Standards ("NSPS") under the federal Clean Air Act. The NSPS is likely to require new sources, and existing sources that carry out modifications, such as the installation of pollution controls, that increase greenhouse gas emissions over a certain threshold to take particular steps to limit their CO2 emissions. Either regulatory approach is likely to establish some cost for emitting CO2 or to achieve required reductions in such emissions.

While the Companies pretend to ignore CO2 costs on the grounds that those costs are purely speculative and unknowable, they in reality treat the CO2 issue as if there were complete certainty around it. In particular, the Companies assign a price of $0 to CO2 emissions, which means that the Companies are asserting certainty that there will not be any regulations or price for CO2 over the 15 year IRP planning period. In fact, in testimony recently filed with the Commission, the Companies claimed that "it would be imprudent" to assume otherwise.[24]

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[24] PSC Case Nos. 2011-00161 and 00162, Rebuttal Testimony of David S. Sinclair at p. 31 lines 11-12.

Numerous other utilities disagree with the Companies' certainty. For example, here is a list of just some of the utilities that have included a price related to CO_2 emissions in recent energy planning:

- In September 2011, Duke Energy Carolinas submitted an IRP in South Carolina that assumed a CO_2 price starting at $12 per ton in 2016 and increasing to $42 per ton by 2031.[25] The filing also used higher CO_2 price assumptions from 2009 and 2010 IRPs as the basis for sensitivity analyses.[26]

- In an August 2011 filing, Georgia Power (a subsidiary of Southern Company) modeled four different CO_2 price scenarios - $0, $10, $20, and $30 per ton – starting in 2015 in order to "span the plausible short term and long term range of CO_2 requirements"[27]

- In July 2011, Duke Energy Ohio submitted an IRP that included a "CO_2 price curve beginning in 2016 to represent the potential for future federal climate legislation."[28]

- In March 2011, the Tennessee Valley Authority submitted an IRP that tested eight scenarios involving CO_2 prices that ranged from $0 throughout the planning period to a price starting at $17 per ton in 2012 and increasing to $94 per ton by 2030.[29]

- In March 2011, PacifiCorp submitted an IRP in Utah in which the utility modeled four different CO_2 price scenarios, ranging from an assumption of no CO_2 price, to prices starting in 2015 at $12, $19, or $25 per ton and escalating at different rates after that through 2030. The utility also modeled two scenarios involving hard caps on overall CO_2 emissions.[30]

- In February 2011, Ameren Missouri submitted an IRP that included an evaluation of CO_2 cap-and-trade scenarios involving a CO_2 cost that started at $7.50 per ton in 2015 and increases to $47.22 in 2040.[31]

- In December 2010, Delmarva Delaware filed an IRP in which it assumes a federal CO_2 price of $20 per ton in 2018, increasing to $25 per ton by 2020.[32]

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[25] Duke Energy Carolinas, LLC's 2011 Integrated Resource Plan (Sept. 1, 2011), at 100-101.
[26] *Id.*
[27] Georgia Power's Application for Decertification and Updated Integrated Resource Plan, Georgia PSC Docket No. 34218 (Aug, 4, 2011), at 37.
[28] Duke Energy Ohio, Inc., 2011 Electric Long Term Forecast Report and Resource Plan, Ohio PUC Case No. 11-1439-EL-FOR (July 15, 2011), at 186.
[29] Tennessee Valley Authority, Integrated Resource Plan: TVA's Environmental and Energy Future (Mar. 2011), at 96.
[30] PacifiCorp, 2011 Integrated Resource Plan (Mar. 31, 2011), at 159-160.
[31] Ameren Missouri, 2011 Integrated Resource Plan (Feb. 2011), at 31.
[32] Delmarva Delaware, IRP Filing Resource Modeling – Supporting Documentation (Dec. 1, 2010), at 16-17.

The Companies are correct that there is uncertainty about what the future cost of CO2 emissions will be. But the proper way to address such uncertainty is not to simply declare that there will be no cost. Instead, prudent utility planning calls for carrying out sensitivity analyses that assume a range of different CO2 prices and assigning reasonable probabilities to each scenario so that the lowest cost plan for approaching likely future scenarios can be developed.

The Environmental Groups recommend that the Companies carry out such analyses using the mid-range, low, and high CO2 price projections set forth in the CO2 price forecast from Synapse Energy Economics that is further discussed in the attached report from Dr. Jeremy Fisher.

VI. The Companies' Evaluation of Supply Side Resources Understates the Substantial Costs Facing the Companies' Aging Coal Units.

The IRP is also flawed because it presents an inadequate assessment of the significant costs that would need to be incurred to keep the Companies' aging coal-fired electric generating units operating throughout the planning period. In their IRP, the Companies rely on an analysis they did in the context of a separate Commission proceeding in which the Companies are seeking Certificates of Public Necessity and Convenience ("CPCN") for the installation of pollution controls on a number of their coal units. In the CPCN proceedings, the Companies carried out Strategist modeling to determine the net present value revenue requirement ("NPVRR") of retrofitting versus retiring each of its coal units. Through that analysis, the Companies concluded that it would be most cost effective to retire the Cane Run, Green River, and Tyrone coal units and decided that the rest of their coal units should be retrofitted to comply with existing and pending U.S. EPA environmental regulations.

As explained in the attached report by Dr. Jeremy Fisher from Synapse Energy Economics, the Strategist modeling carried out by the Companies was flawed in a number of ways that understate the substantial costs facing the Companies' coal units. Specific flaws in the modeling identified by Dr. Fisher include:

- **Natural gas price correction:** The Companies' base-case natural gas price forecast appears to inappropriately represent the highest end of gas price assumptions;
- **SCR cost:** The Companies have inappropriately dismissed the risk that some of its units may require selective catalytic reduction (SCR) to meet emissions limits for oxides of nitrogen (NO_x) under both promulgated and proposed ozone standards;
- **CO_2 price risk**: The Companies have assumed that there is no chance that the federal government will regulate carbon dioxide (CO_2) emissions anytime in the future, thereby exposing ratepayers to a very real financial risk;

- **Oversized replacement capacity:** The Companies assume that replacement generation is only available from three types of natural gas plants, a single-cycle turbine of 194 MW, and two combined cycle sized at 605 and 907 MW (summer capacity), respectively. These large-size combined cycle units are larger than many of the coal units under consideration, forcing the model to only evaluate unduly expensive alternatives that present potentially non-optimal solutions.

- **Utility modeled in isolation:** The model used by the Companies assumes that they have no interactions with the Eastern Interconnection, which forces the model into unrealistic solutions.

- **Emergency generation purchases:** The model uses a very high cost for emergency generation with an unreasonably high frequency, resulting in very high costs with no apparent basis.

- **NO_x and SO_2 Prices:** The Companies have assumed that the trading price of NO_x and sulfur dioxide (SO_2) will diminish to zero in two years, in contradiction to EPA estimates; thereby denying the Companies the opportunity cost of avoiding these emissions through retirement or emissions controls.

- **Order of Retirement:** The Companies have chosen a semi-arbitrary order in which to test the retire/retrofit decision without regard to the impact that this order imposes on the modeled economic merit of each unit. Simply changing this order could result in a more optimal solution and retire/retrofit decisions.

Synapse reran the modeling carried out by the Companies using more reasonable assumptions regarding natural gas prices, CO2 prices, and the need for SCRs, and found that the NPVRR of retrofitting each of the Companies' coal units declined significantly. That modeling showed that the economics generally favors retirement, rather than retrofitting, of Brown Units 1 and 2 and, depending on the scenarios, a number of the other Companies' other coal units were also more economic to retire rather than retrofit.[33]

The new modeling analyses performed by Synapse also understates the costs facing the Companies' coal units, as limited time and resources restricted the number of factors that could be fully evaluated and modeled. Additional costs or not reflected in either the Companies or the Synapse modeling that are relevant to the question of whether Brown Units 1 and 2 and other coal units should be retired or retrofitted include:

- **Age of the Coal Units:** As the Companies note, the typical design life for coal unit is 50 years. (IRP at 5-49). Put into service, Brown Unit 1 has already exceeded that design life, and Brown Unit 2 will turn 50 years old in 2013. The Companies have noted that, based on a "life assessment study" the probable retirement year for those two units is

[33] Dr. Fisher Report at Ex. JIF-E2.

guidelines, despite the risk that these costs could be large and that these regulations could require capital investments within the time period of this IRP. Rather than quantitatively considering scenarios that include cost of compliance with coal combustion waste regulation, the IRP notes that "The companies will continue to review this issue." (IRP at 8-137). The IRP contains the same statement regarding regulation of cooling water intake structures, and again regarding Clean Water Act effluent guidelines. (IRP at 8-106, 8-134).

Determining the most economically efficient resource option requires a comprehensive and detailed assessment of the costs associated with a variety of options. This assessment must include a full understanding of all of the costs that are associated with specific options, such as retrofitting potentially inefficient and aging coal plants to make them compliant with environmental regulations, as well as an understanding and evaluation of costs and the risk of costs that can reasonably be anticipated for specific options. The IRP submitted by the Companies does not satisfy these basic standards.

VII. The Need to Factor In Uncertainty

A final, overarching concern about the IRP is that it does not assess the uncertainties and risks attendant on a resource plan. A resource plan that is projected to have the lowest life cycle cost under one set of assumptions about the future, may or may not also be the best under another set of assumptions. Assumptions that can make a material difference to the performance of resource plans include, but are not limited to, (1) load growth and other factors affecting the size and timing of resource needs over time, such as trends in customer types, end use make up and load shape, (2) cost, availability and deliverability of fuels, equipment, construction materials and expertise, labor, land, transmission service and other goods and services that determine the cost of the various resources in the portfolio, (3) financial factors, such as inflation rates, utility bond ratings and changes in the rating criteria, cost and availability of various types of insurance, cost and availability of various types of capital, (4) factors relating to implementation schedules and "lumpiness" of various resource options, such as construction or installation times or delays in those times, risk of project failure or cost increase, (5) environmental and regulatory risks, such changes in emission standards (including the likelihood of CO_2 regulations), new emission standards or fees, permitting risk, and (6) planning risk, for example, the risk that a resource will become obsolete or unnecessary while under construction.

While the technicalities can be somewhat abstract, the essence of risk and uncertainty assessment in this context is to measure the variability of a resource portfolio's results due to uncertainties in factors or assumptions. The IRP should, but does not, contain (1) a thorough inventory and description of the relevant risks, together with an assessment of their probabilities, (2) an objective analysis of how those risks impact the performance of various resource plans individually and in combination, (3) development of a plan relying on a portfolio of resources that manages risk and uncertainty to a reasonable level while delivering the lowest life-cycle cost over the fullest possible range of plausible future scenarios.

VIII. Conclusion

In order to ensure that the Companies go down the path of the lowest cost approach for meeting their customers' energy needs, the Companies should address and correct the above errors in their IRP.

Respectfully submitted,

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Dated: November 23, 2011

CERTIFICATE OF SERVICE

I certify that I served a copy of Environmental Groups' Comments via first class mail on November 23, 2011, to the following:

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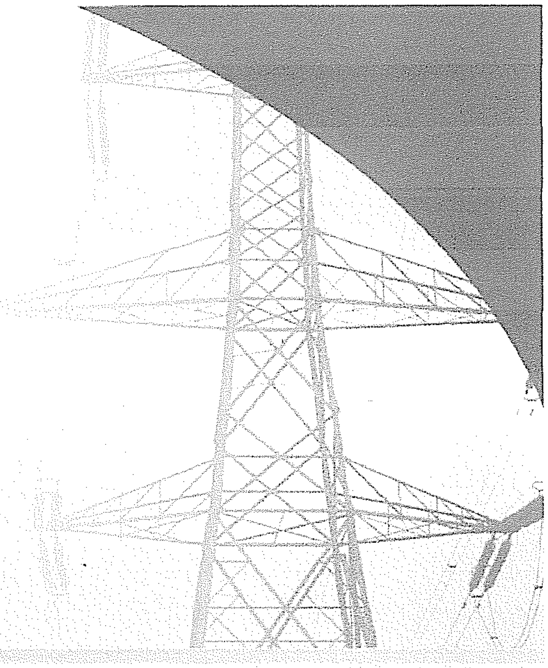

Recommendations for the Treatment of Controllable Capacity Demand Response Programs in Reserve Margin Calculations

Prepared by the Resource Issues Subcommittee for the NERC Planning Committee

June 1, 2010

to ensure
the reliability of the
bulk power system

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1. Background

At the December 2009 Planning Committee (PC) meeting, the Data Coordination Working Group asked the PC to:

> Assign the appropriate group to review Reserve Margin calculations, which either includes dispatchable, controllable capacity demand response as a supply-side resource or a demand-side on-peak load modifier as well as identify the best approach to be used *in NERC's Reliability Assessments*.

The Resource Issues Subcommittee (RIS) was assigned this task.

Four types of programs are categorized by NERC as "controllable capacity demand response" (CCDR) in the NERC 2009 Long Term Reliability Assessment:

1. **Direct Control Load Management (DCLM)** – Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.
2. **Contractually Interruptible (Curtailable) Demand** – Demand-Side Management achieved by a customer reducing its load upon notification from a control center. The interruption must be mandatory at times of system emergency. Curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. It is the magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Regional Entity's seasonal peak. In some instances, the demand reduction may be effected by action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions.
3. **Critical Peak Pricing (CPP) with Control** – Demand-Side Management that combines direct remote control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.
4. **Load as a Capacity Resource** – Demand-side resources that commit to pre-specified load reductions when system contingencies arise. These resources are not limited to being dispatched during system contingencies. They may be subject to economic dispatch from wholesale balancing authorities or through a retail tariff and bilateral arrangements with a third-party curtailments service provider. Additionally, this capacity may be used to meet resource adequacy obligations when determining planning Reserve Margins.

The RIS made a recommendation at the March 2010 PC meeting that CCDR resources that could be activated, directly or indirectly, by a Balancing Authority (BA) should be consistently treated as a resource, similar to generating capacity, in NERC Reserve Margin calculations. If CCDR cannot be activated by a BA, it should be considered a load reduction in the NERC Reserve Margin calculation. Emergency measures such as voltage reduction should be excluded altogether. This recommendation was not approved by the Planning Committee, and the RIS was asked to:

1. Provide examples of how its proposed method would be used in several areas: ERCOT, PJM, MISO, NYISO, and others deemed appropriate.
2. Reevaluate its equations and use new terminology if needed.
3. Review the Reliability Standards and identify any that are related to the reserve margin definition or demand response.

This report answers these questions. **The RIS still recommends that BA-controlled CCDR be treated as a resource in NERC Reserve Margin calculations.** However, additional rationale and definitions are provided to support this recommendation.

2. Terminology and Equations

With regard to terminology, the RIS believes several new definitions would assist in the calculation of Reserve Margin. Table 1 on the next page shows the definitions needed for both alternatives – treating all Reportable CCDR as a resource or treating all Reportable CCDR as a load reduction. The terms "Reportable CCDR MW" and "Reporting Criteria" are more thoroughly discussed in Section 6.

The % Reserve Margin can be calculated with two different formulas, each of which produces the same result.

$$\%\text{ Reserve Margin} = \left[\frac{(\text{Capacity} - \text{Load})}{\text{Load}}\right] \times 100\% = \left[\frac{\text{Capacity}}{\text{Load}} - 1\right] \times 100\%$$

This report uses the second formula. The formulas below show the % Reserve Margin calculated for each alternative treatment of CCDR.

% Reserve Margin with all Reportable CCDR treated as a resource:

$$\left[\frac{\text{Generating Capacity} + \text{Reportable CCDR MW}}{\text{Forecasted Total Internal Demand}} - 1\right] \times 100\% \qquad \textit{[Equation 1]}$$

% Reserve Margin with all Reportable CCDR treated as a load reduction:

$$\left[\frac{\text{Generating Capacity}}{\text{Forecasted Total Internal Demand} - \text{Reportable CCDR MW}} - 1\right] \times 100\% =$$

$$\left[\frac{\text{Generating Capacity}}{\text{Forecasted Net Internal Demand}} - 1\right] \times 100\% \qquad \textit{[Equation 2]}$$

Regardless of how these programs are treated for Reserve Margin purposes, the programs do reduce load when they are implemented. That fact is not controversial. As shown on Table 2 (Section 4), entities now treat Reportable CCDR is various manners. Regardless of what action the PC takes, some entities will have differences between how they report Reserve Margin for their own internal assessments how they report Reserve Margin for NERC Reliability Assessments.

Table 1
Definitions Needed Whether Reported CCDR
Is Reported as a Resource of a Load Reduction

1. Add "Reportable CCDR" which means a CCDR program that meets the Reporting Criteria.
2. Add "Reportable CCDR MW" which means the expected MW of load reduction coincident with the system peak associated with a Reportable CCDR program, assuming the program is fully implemented. This definition is parallel to the Expected On-Peak Capacity used for wind, solar, or hydro.[1]
3. Add "Reporting Criteria" *which means that for a CCDR program to be reported in NERC* Reliability Assessments, it must meet <u>all</u> of these criteria:
   a. Can the activated, directly or indirectly, by a BA
   b. Has an obligation to perform[1]
4. Add "Forecasted" to "Total Internal Demand." The new definition would be "Forecasted Total Internal Demand." Also, change the present definition of "Total Internal Demand."
   a. The present language has phrases such as "the sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system" that implies it is an "actual" as opposed to a "forecasted" quantity.
   b. The new definition should clarify that the impact of load reduction from <u>non-</u>Reportable CCDR is included.
5. Add "Forecasted" to "Net Internal Demand" so that Forecasted Net Internal Demand = Forecasted Total Internal Demand – Reportable CCDR MW
6. Define "Actual Net Internal Demand" as the highest demand level reached after the <u>actual</u> implementation of Reportable CCDR programs.
7. Define "Actual Total Internal Demand" as Actual Net Internal Demand with the impact of actual implemented Reportable CCDR added back.

[1] Additional discussion is provided in Section 6.

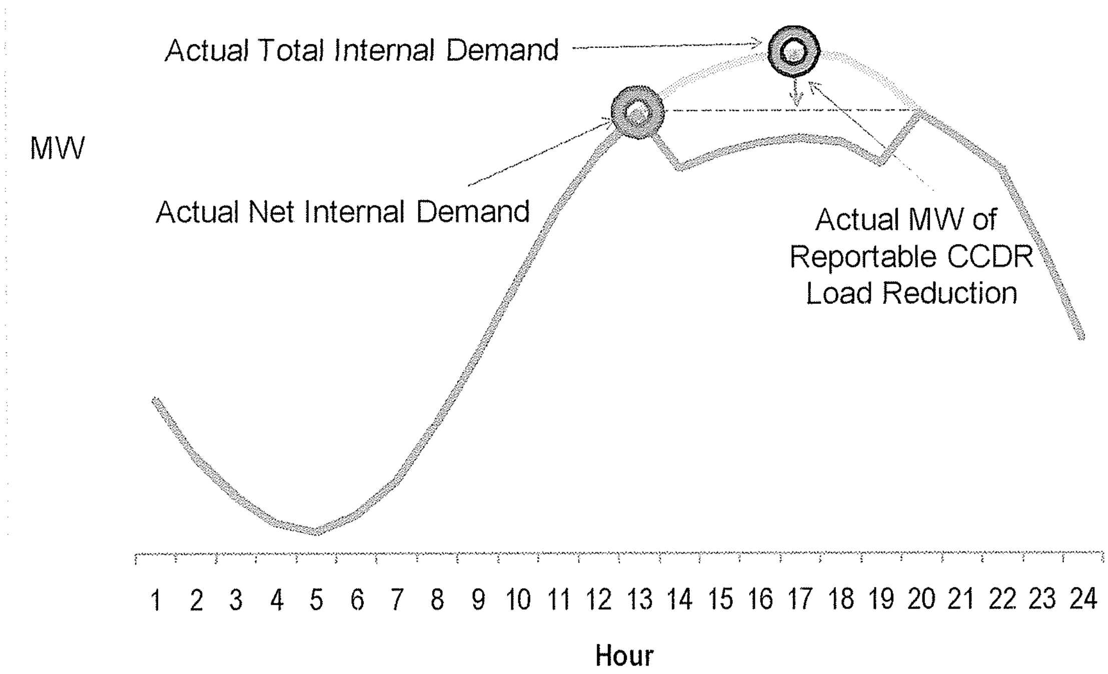
3. Comparison of Methods

1. Treating Reportable CCDR as a resource is similar to how wind, solar, and hydro are reported in Reliability Assessments.
2. Treating Reportable CCDR as a load reduction results in increasing % Reserve Margin to ensure the same level of reliability as Reportable CCDR increases. Consider the situation where a system has a 100 GW demand, 110 GW of generation and 5 GW of Reportable CCDR. If Reportable CCDR is reported as a resource, the Reserve Margin is (115/100 -1) = 15.0%. If Reportable CCDR is reported as a load reduction, the Reserve Margin is (110/95 – 1) = 15.8%. But both systems have the same reliability.

   Now double the amount of Reportable CCDR from 5 GW to 10 GW and reduce the amount of generation by the same amount, from 110 GW to 105 GW. If Reportable CCDR is reported as a resource, the Reserve Margin is still 15.0%. However, if Reportable CCDR is reported as a load reduction, the Reserve Margin is (105/90 – 1) = 16.7%. Both systems have the same reliability, yet by treating Reportable CCDR as a load reduction, the Reserve Margin increased from 15.8% to 16.7% with no change in the actual MW of Reserve Margin. All four examples above have the same MW Reserve Margin of 15 GW.
3. With the definitional changes in Table 1, the comparisons of "actual" with "forecasted" demands under both options can be compared.
   a. If all Reportable CCDR is treated as a resource, then all demands in NERC's Reliability Assessments would be reported as Actual or Forecasted Total Internal Demand since those are used in Reserve Margin calculations. This will result in more consistent comparisons:
      i. Forecasted Total Internal Demand would be comparable between reporting areas, so that parameters such as load growth rates can be compared. The reason is that this term excludes the subtraction of Reportable CCDR MW for all programs.
      ii. Actual Total Internal Demand can be compared to Forecasted Total Internal Demand since both terms exclude the Reportable CCDR MW of all programs. Planners and forecasters need Actual Total Internal Demand since it is unaffected by Reportable CCDR resource decisions. *See Figure 1 on the page 5.*
   b. If all Reportable CCDR is treated as a load reduction, then all demands in NERC's Reliability Assessments would be reported as Actual or Forecasted Total Internal Demand since those are used in Reserve Margin calculations. This will result in inconsistent comparisons:
      i. Forecasted Net Internal Demand is <u>not</u> comparable between reporting areas with respect to parameters such as load growth rates. To be comparable, one would need to assume that Reportable CCDR is growing at the same rate as Forecasted Total Internal Demand.
      ii. Actual Net Internal Demand <u>should not</u> be compared to Forecasted Net Internal Demand. The reason is that Actual Net Internal Demand only excludes the MW of Reportable CCDR for programs that were actually implemented, whereas Forecasted Net Internal excludes the Reportable CCDR MW for all programs.

The actual MW of Reportable CCDR programs actually implemented will generally be less than the total MW than could have been fully implemented.

Figure 1



Planners need "Actual Total Internal Demand" "Actual Total Internal Demand" is directly comparable with "Forecasted Total Internal Demand" since neither has any Reportable CCDR MW deducted.

4. Existing Treatment of Reportable CCDR Programs

The RIS examined several organizations for their current practices of treating Reportable CCDR programs in their own Reserve Margin calculations

The results are summarized in Table 1 below. None of the organizations had Critical Peak Pricing with Control. An "R" indicates that the program is treated as a resource and an "LR" indicates that it is treated as a load reduction. This limited sample of organizations shows a diverse pattern of treatment in their own Reserve Margin calculation.

Any organization that treats Reportable CCDR as a load reduction for its own Reserve Margin calculations would have a slightly lower NERC Reserve Margin reported for Reliability Assessments.

Table 2

Current Treatment of Reportable CCDR in Reserve Margin Calculations

Organization	Direct Control Load Management	Interruptible/ Curtailable Demand	Load as a Capacity Resource
PacifiCorp	R	R	
Idaho Power	LR	LR	
FRCC	LR	LR	
NYISO			R
ISO-NE		R	
PJM		LR	LR
MISO	LR	LR	
ERCOT		LR	LR
IESO		R	R
TVA	R	LR	

5. Reliability Standards and Reserve Margin

Although no Reliability Standards address Reserve Margin calculations, several Modeling, Analysis, and Data (MOD) standards do touch on Reserve Margin parameters. **None of them are presently monitored for compliance.**

1. MOD-017.1, R1.1, requires "integrated hourly demands" for the prior year, but it does not require hourly MW adjustments to create "Actual Total Internal Demand."
2. MOD-021-0.1, R1, requires documentation on how various Demand-Side Management programs, including Direct Control Load Management and Interruptible Demand, are addressed in load forecasts. A single load forecast framework is not required so that Reportable CCDR MW could be deducted or not deducted from the load forecast.

6. Reporting Criteria and Reportable CCDR MW

The discussion in this section applies to both alternatives for treating Reportable CCDR programs in Reserve Margin calculations. Some of the definitions were previously discussed in Table 1 in Section 2 and are more thoroughly discussed below.

1. Reporting Criteria. To be reported in NERC Reliability Assessments, a CCDR program must meet all of the Reporting Criteria (a and b) below:

   a. Can be activated, directly or indirectly, by a Balancing Authority.

      Discussion: Non-BA controlled CCDR programs are not fully known by BAs, and even if known, they cannot be relied upon by the BA to assist when needed by the BA. For example, a municipality purchasing all its power may have a CCDR program to manage its purchases, but that program need not be coordinated with or even reported to the seller or the BA. The municipality's "firm load" from the seller's perspective will have the municipal's use of its CCDR program deducted. Likewise, non-BA controlled CCDR impacts need to be deducted in arriving at the Forecasted Total Internal Demand.

   b. Has an obligation to perform such as:

      i. Penalties for non-performance
      ii. A requirement to submit a market bid
      iii. A remotely-controlled switch installed to cycle-off load

      Discussion: An obligation to perform ensures MW are known or estimated and hence available for reporting; it also ensures MW will be available when needed. Direct Control Load Management program customers are different. While they have no specific obligation to perform, they have made commitments to have their appliances cycled, and these commitments are relied upon like "iron in the ground." Customer-specific performance requirements are not feasible, but aggregate response may be estimated from observation.

2. Defining Reportable CCDR MW

   a. Report the expected MW of load reduction coincident with system peak. This may be the contracted amount, if that is expected. It assumes the program is fully implemented. This definition is parallel to the Expected On-Peak Capacity used for wind, solar, or hydro.

   b. Incorporate avoided transmission and distribution losses into the expected MW reduction as appropriate. These assumptions will be specific to both the reporting entity and the program.

   c. For Reportable CCDR that is treated as a resource, do not gross up the expected MW reduction for the entity's planning Reserve Margin. One entity proposed that if Reportable CCDR is moved from a load reduction to a resource that the Reportable CCDR MW should be grossed up by the entity's planning Reserve Margin. For example, if an entity has a 15% planning Reserve Margin and Reportable CCDR program's load reduction of 100 MW, the program's MW would be increased to 115 MW if the program is reported as a resource. This increases Reserve Margin by 15 MW while maintaining the same % Reserve Margin. However, these added MW are "paper" MW only. Whether Reportable CCDR is treated as a resource or a load reduction, the MW of Reserve Margin does not change. More importantly, the MW of Reserve Margin does not need to change since the same uncertainties that a Reserve Margin addresses (e.g. unit outages, load forecast uncertainty, etc.) are present irrespective of how the % Reserve Margin is calculated.

7. Recommendations

In conclusion, the RIS recommends that:

1. **In NERC Reliability Assessments, include Reportable CCDR as a resource in Reserve Margin calculations.**

2. **Reportable CCDR must meet the criteria that they:**
   a. **Can the activated, directly or indirectly, by a BA; and**
   b. **Have an obligation to perform.**

3. **Reportable CCDR MW should:**
   a. **Incorporate an adjustment for avoided transmission and distribution losses that is appropriate to the reporting entity and program; and**
   b. **Not gross up load reduction for reserve margin.**

4. **For NERC Reliability Assessments, report Forecasted Total Internal Demand as the primary demand statistic.**

PACIFICORP

November 18, 2010

Stochastic Loss of Load Study for the 2011 Integrated Resource Plan

INTRODUCTION

PacifiCorp evaluates the desired level of capacity planning reserves for each integrated resource plan. For the 2011 IRP, the Company conducted a stochastic loss of load study to help identify the target capacity planning reserve margin (PRM) to use for resource portfolio development. The PRM value used for the 2008 IRP and 2008 IRP Update was 12%.

This study utilized the Company's stochastic production cost simulation system, Planning and Risk (PaR), to determine the relationship between PRM and resource adequacy as measured by Loss of Load Probability (LOLP) index. Loss of load probability represents the probability that generation in a given hour is insufficient to serve load. Accumulating the number of hours for which the system experiences unserved load over a given period, typically one year, yields the LOLP index. Once the relationship between LOLP and PRM is established for PacifiCorp's system, a target LOLP level is selected to determine the PRM for subsequent resource portfolio development. This report describes the loss of load study and modeling assumptions, the selection of a target loss of load criterion, and the adoption of a PRM for portfolio development. The last comprehensive stochastic study conducted was for PacifiCorp's 2004 IRP.[1] Major differences between this study and the last one include (1) significantly more wind resources and incorporation of incremental wind operating reserves in the resource portfolio simulations, (2) expansion of the transmission topology from two bubbles to 26, and (3) incorporation of energy efficiency programs as a resource with a reserve credit rather than a reduction to the load forecast.

Note that while this study reports the incremental resource cost for achieving a given loss of load frequency and associated reserve margin level using a standard reliability resource type, it does not assess the trade-off between reliability and cost or the optimal resource mix to achieve a given reliability level. PacifiCorp compares different resource portfolios based on the amount and cost of unserved load (megawatt-hours of "Energy Not Served" or ENS) resulting from stochastic simulations of many portfolios built to meet a given PRM level. This stochastic analysis reveals the reliability impacts and costs associated with different resource mixes.

LOSS OF LOAD PROBABILITY METRICS

The metric used to derive the LOLP index is Loss of Load Hours (LOLH). The PaR model records a LOLH event when load is not met for an hour. This condition results from unit outages that reduce available generation capacity in a load area below the load derived from the Monte Carlo draws conducted by the PaR model. The LOLH event also has an associated Energy Not Served value, which is the magnitude of the lost load for the hour.

[1] See Appendix N of the 2004 IRP Technical Appendix Volume.

The PaR model's reported LOLP index is the average number of LOLH events for PacifiCorp's 100-iteration Monte Carlo production cost simulation.[2]

SIMULATION PERIOD

PacifiCorp selected 2014 as the simulation test year for the LOLP study. This year aligns with the start of the 2014-2016 resource acquisition period targeted by the Company's All Source RFP issued to the market on December 2, 16 2009. This year also aligns with major planned Energy Gateway transmission additions: the Mona-Oquirrh segment of Energy Gateway Central by June 2013, and the Sigurd-Red Butte segment by June 2014.

MODELING APPROACH OVERVIEW

The LOLP modeling approach entailed adding incremental reliability resource capacity to a starting point resource portfolio to reach increasingly higher target PRM levels. Loads and resources reflect those of the September 21, 2010 preliminary capacity load & resource balance, as presented at the October 5, 2010 IRP public input meeting.[3] This balance uses the annual system coincident peak load forecast prepared in September 2010 for use in the Company's 2011 business plan. The starting PRM level was 8.3%, which covers system operating reserve requirements (contingency and regulating reserves). Reliability resource capacity was then added to reach planning reserve margin levels of approximately 10%, 12%, 15%, and 18%. PacifiCorp conducted stochastic Monte Carlo simulations for each of the five resource portfolios built to achieve the target PRMs. The stochastic simulations account for Western Electricity Coordinating Council (WECC) operating reserve obligations plus incremental operating reserves for existing and forecasted wind additions as of year-end 2013. PacifiCorp then extracted LOLH and associated LOLP statistics from the portfolio simulations to characterize the reliability impacts of the incremental reliability resource capacity.

PLANNING RESERVE MARGIN BUILD-UP

PacifiCorp used an intercooled aeroderivative simple-cycle combustion turbine (IC aero SCCT) as the reliability resource for the loss of load study. Starting from a portfolio with approximately a zero PRM, IC aero SCCT capacity blocks were added to PacifiCorp's East and West Balancing Authority Areas—PacifiCorp East (PACE) and PacifiCorp West (PACW)—until reaching the desired PRM. The capacity build-up includes 77 MW of non-owned reserves held for other parties located in PacifiCorp's Balancing Authority Areas. Additionally, since reserves are not needed to be held for energy efficiency resources (Class 2 demand-side management), PacifiCorp included a reserve credit for the incremental 307 MW of Class 2 DSM capacity added by 2014. Modeled SCCT units were sized as follows by Balancing Authority Area:

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[2] Calculating a probability using LOLH is a variant of the Loss of Load Expectation (LOLE) statistic.

[3] The preliminary 2011 IRP capacity load and resource balance is reported on page 45 of the meeting presentation, which can be downloaded at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/PacifiCorp_2011IRP_PIM4_10-05-10.pdf

- PacifiCorp East Units - 93 MW (1 unit), 186 MW (2 Units), 279 MW (3 Units)
- PacifiCorp West Units - 102 MW (1 unit), 205 MW (2 Units), 307 MW (3 Units)

Regarding resource placement, PacifiCorp added SCCT capacity to transmission areas as dictated by PRM needs, with most resources placed in the West Main ("West Units") and Utah North ("East Units") transmission areas. Table 1 shows the megawatt capacity added to reach the target PRM levels. Since capacity is added in blocks, the resulting PRM levels vary from the original target levels.

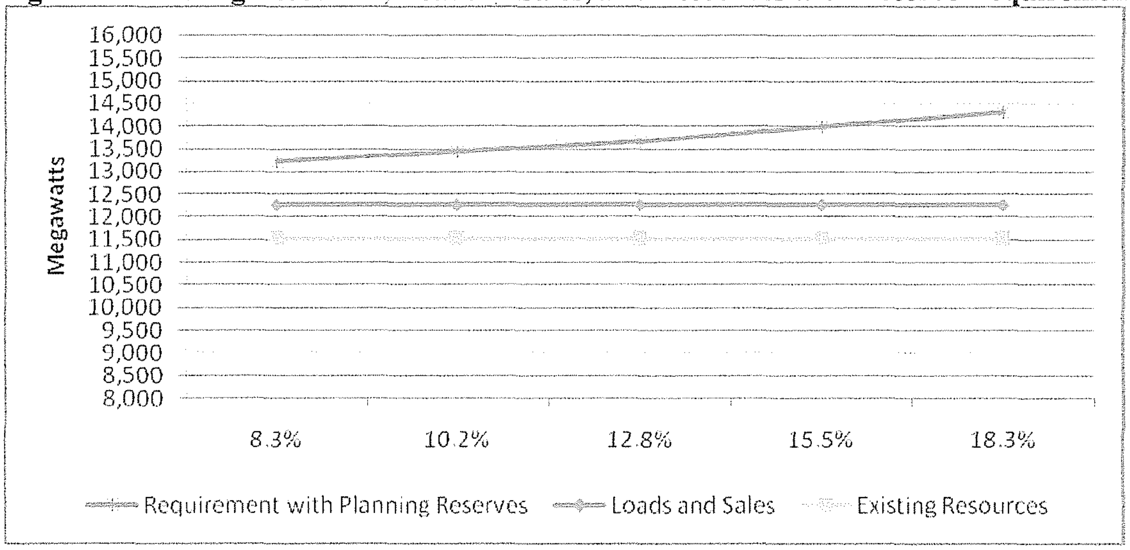
Table 1 – Resource Capacity Additions Needed to Reach PRM Target Levels

Resource	Planning Reserve Margin Level 8.3%	10.2%	12.8%	15.5%	18.3%
East 3 Unit	837	1,116	1,116	1,395	1,674
East 2 Unit	186	0	186	0	0
East 1 Unit	0	0	0	93	0
Goshen	186	186	186	186	186
West 3 Unit	0	0	307	307	307
West 2 Unit	0	205	0	0	0
West 1 Unit	102	0	0	102	205
Walla Walla	102	102	102	102	102
Total IC Aero SCCT Capacity	1,413	1,609	1,897	2,185	2,474
DSM with Reserve Credit	332	338	344	353	362
Total Capacity Added*	1,745	1,947	2,241	2,539	2,836

* Excludes non-owned reserves held for other parties within PacifiCorp's service territory.

Figure 1 shows the relative magnitude of existing resources, the load obligation plus sales, and resources with incremental reserves required to reach the target PRM.

Figure 1 – Existing Resources, Loads & Sales, and Resources with Reserve Requirements



MONTE CARLO PRODUCTION COST SIMULATION

For the loss of load study, the PaR model is configured to conduct 100 Monte Carlo simulation runs. During model execution, PaR makes time-path-dependent Monte Carlo draws for each stochastic variable. The stochastic variables include regional loads, unit outages, hydro availability, commodity natural gas prices, and wholesale electricity prices. In the case of natural gas prices, electricity prices, and regional loads, PaR applies Monte Carlo draws on a daily basis. Figures 2 through 9 show a sample of first-of-month daily loads by transmission area resulting from the Monte Carlo draws. In the case of hydroelectric generation, Monte Carlo draws are applied on a weekly basis.

Twelve representative weeks for each month, including the July system peak week, were modeled on an hourly basis. This representative-week approach reduces the model run-time requirements while ensuring that unit dispatch during the critical capacity planning periods is captured in the system simulations. Since only one year was simulated, the stochastic model's long-term stochastic parameters were turned off.

Figure 2 – Utah North Load Area

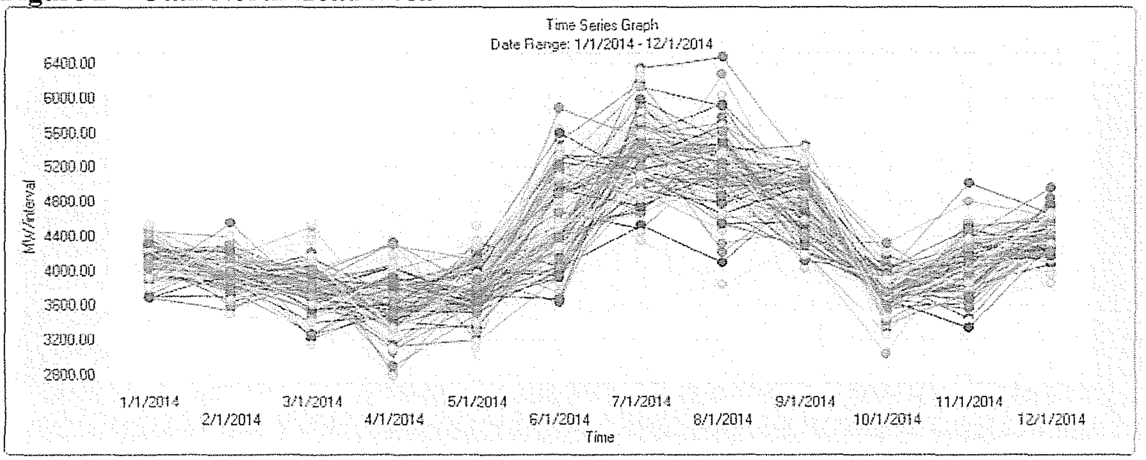


Figure 3 – Utah South Load Area

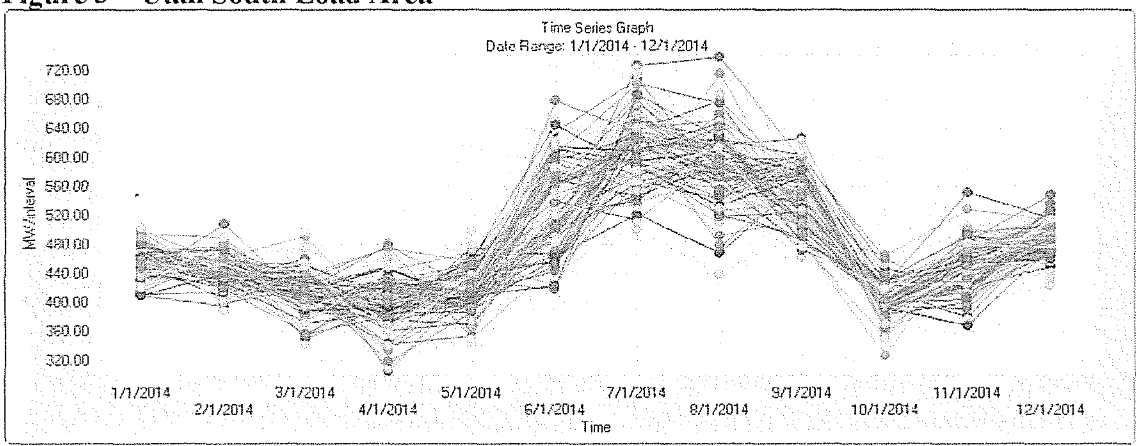


Figure 4 – Walla Walla, Washington Load Area

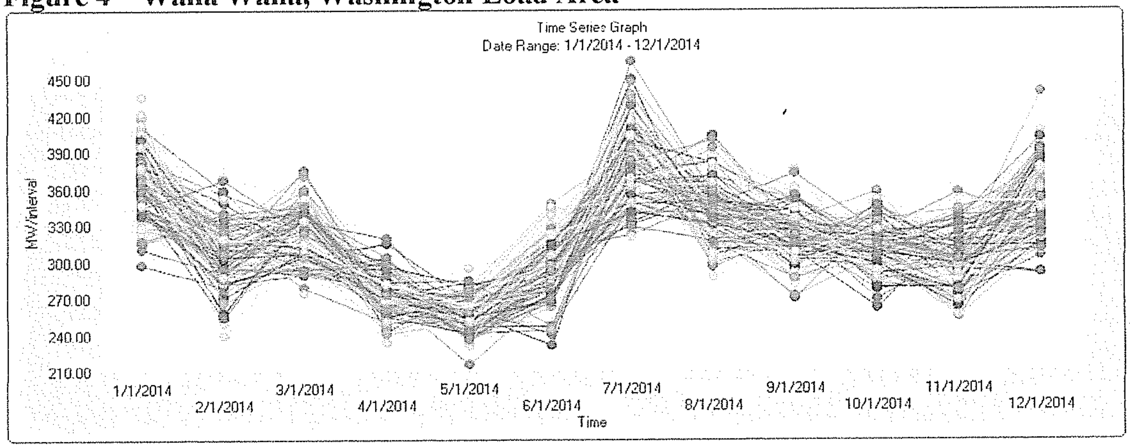


Figure 5 – West Main (Oregon, Northern California) Load Area

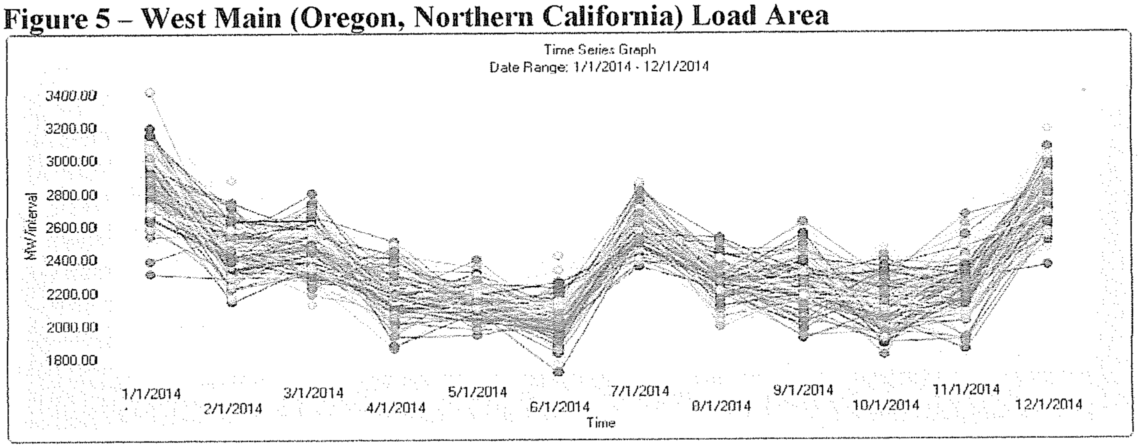


Figure 6 – Yakima Load Area

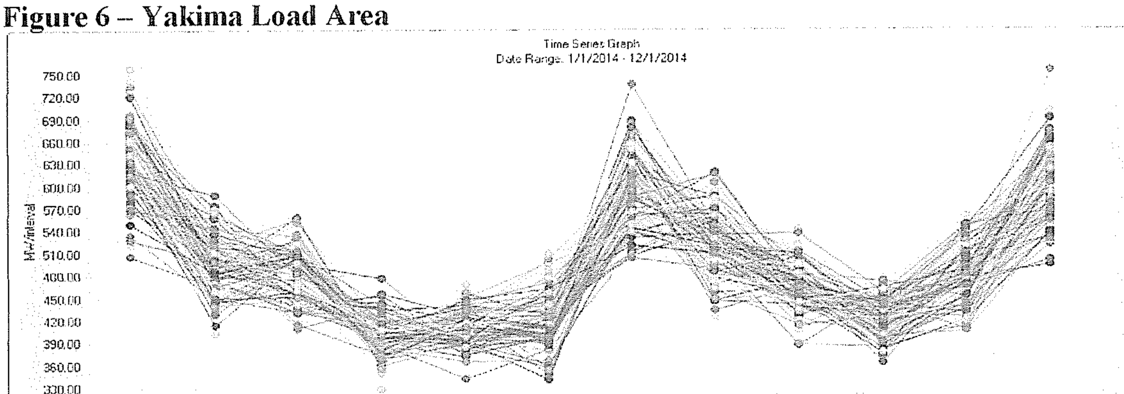


Figure 7 – Goshen Idaho Load Area

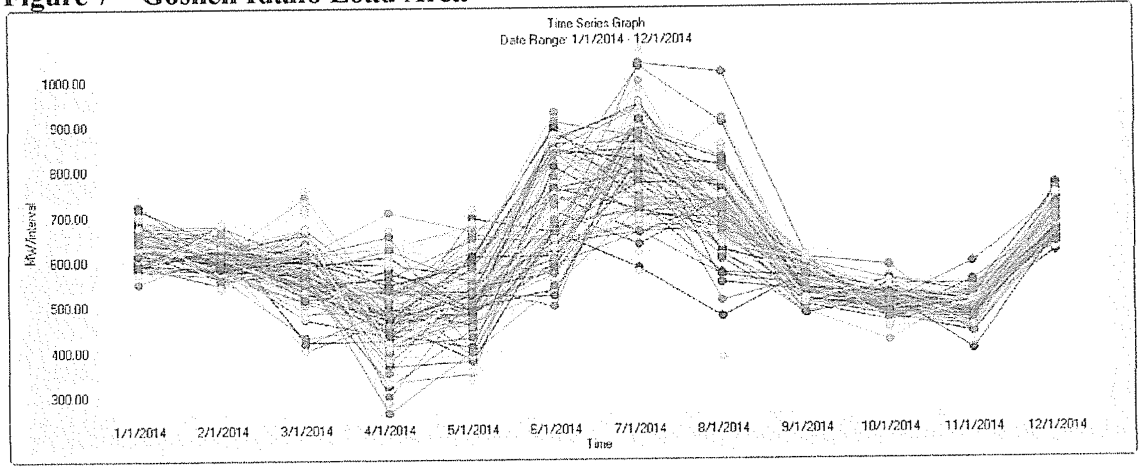


Figure 8 – Northeast Wyoming Load Area

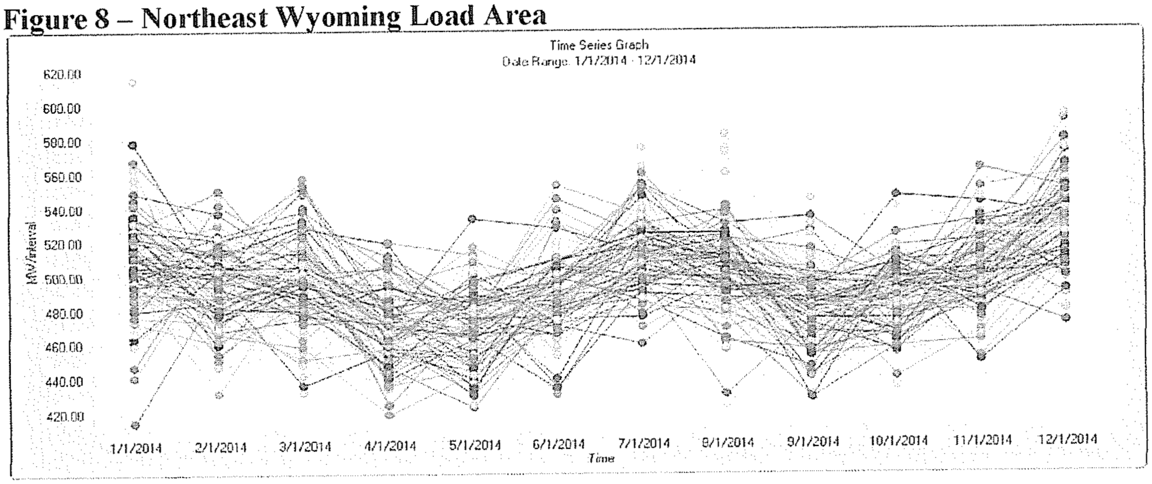
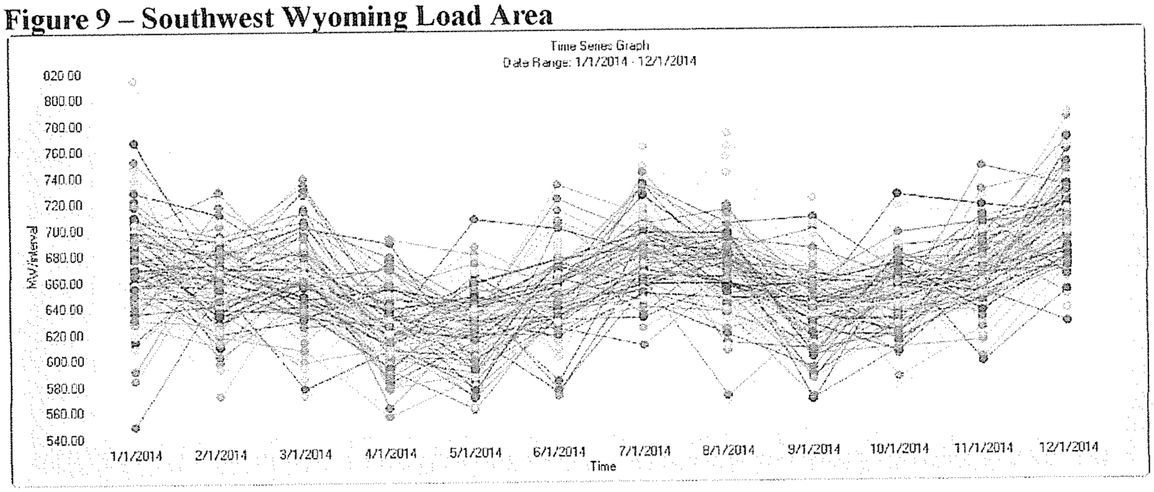


Figure 9 – Southwest Wyoming Load Area



MODELING OPERATING RESERVES

As part of the WECC, PacifiCorp is currently required to maintain at least 5% and 7% operating reserve margins on hydro and thermal load-serving resources, respectively. The Northwest Power Pool (NWPP) also requires a 5% operating reserve margin on wind. In the PaR model, operating reserves are modeled as a function of load. The maximum reserve amount that each generating unit can carry is specified in the model. The PaR model also includes 1.6% of loads to cover the WECC regulating reserves requirements. The operating reserve percentages, exclusive of wind, equate to 8.6% for the East Balancing Area and 8.1% for the West Balancing Area. These operating reserves are split into, roughly, 60-percent spinning and 40-percent non-spinning reserves to comply with WECC spinning and non-spinning reserve requirements.[4] An additional 14% incremental operating reserve requirement is applied against nameplate wind capacity (211 MW) to cover incremental operating reserves for wind as determined by PacifiCorp's 2010 wind integration study.

The operating reserve modeling approach does not address the impact of resource type (i.e., hydro, wind, or thermal) in determining required operating reserves. Operating reserves count toward the PRM, but the required percentages for the Balancing Authority Areas (8.6% and 8.1%) stay constant regardless of resource mix.

All Balancing Authorities within the Northwest Power Pool are also required to participate in the Contingency Reserve Sharing Program. This program provides 60-minute recovery assistance following the loss of a generating resource or transmission path, or failure of a generating unit to start up or increase output. This assistance is provided after the Balancing Authority uses up its Contingency Reserve Obligation (i.e., 7% of load served by thermal resources; 5% of load served by hydro reserves). The reserve sharing program provides a benefit to the utility by covering the first hour of an outage. For recording LOLH and calculating LOLP, the stochastic simulation should omit the first hour of a forced outage event in order to capture reserve sharing benefits. Implementing this functionality in the PaR model requires that a "shadow" station be assigned to each unit with a capacity equal to the unit MW rating and energy equal to the full load output. The shadow station is called upon in the event of a unit outage, thereby contributing emergency generation for one hour during the outage period. (The PaR model would determine that hour based on the marginal energy cost during the outage period.)

This modeling approach was judged to be too complex to implement and validate in time for use in the 2011 IRP. However, this approach was implemented for an loss of load study conducted by the PaR model vendor, Ventyx LLC, for Public Service Company of Colorado. The impact to the PRM of modeling reserve sharing rules of the Rocky Mountain Reserve Group (RMRG) was a reduction of 1.5 percentage points.[5] While the RMRG reserve sharing rules provide for up to two hours of contingency reserve assistance as opposed to the one hour for the Northwest Power Pool's program, the RMRG rules are more restrictive in other respects. For example, reserve

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[4] At least half of the operating reserves must be Spinning Reserve. Spinning reserve is the margin of generating capacity available to replace lost capacity and provide the regulating margin to follow load; spinning capacity must be synchronized to the system and ready to provide power instantaneously. Non-spinning reserve is generating capacity that is not synchronized to the system but can be available within a few hours.

[5] The loss of load report is available at:
http://www.xcelenergy.com/SiteCollectionDocuments/docs/CRPReserveMarginStudy.pdf

support is targeted for units at least 200 MW in size, is provided only to the unit with the largest capacity in the event that two or more units experience simultaneous outages, covers only one outage event per month, and covers less than the full unit capacity due to a smaller pool of member reserves available. Given these offsetting limitations, PacifiCorp assumes that a PRM reduction of 1.5 percentage points is a reasonable proxy for the NWPP's reserve sharing benefit.

STUDY RESULTS

Figure 10 reports the LOLH counts for the five PRM levels modeled, while Figure 11 reports the resulting LOLP index values (the stochastic average for the 100 Monte Carlo iterations). Fitted curves highlight the smooth relationship between the reliability statistics and the PRM level.

Figure 12 reports the total fixed cost of meeting each PRM level based on the incremental IC aero SCCT resource capacity required. The per-unit fixed cost is approximately $191/kW-year, which is grossed up to account for a 2.7% expected forced outage rate. Each percentage point increase in the PRM translates into an incremental fixed cost of about $42 million.

Figure 10 – System LOLH by Planning Reserve Margin Level

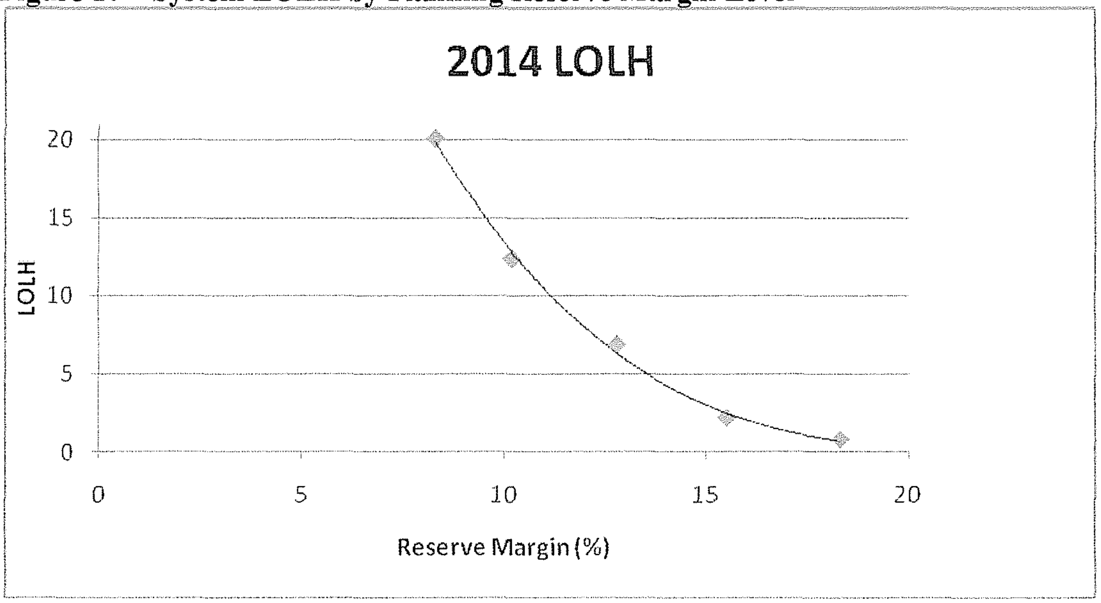


Figure 11 – System LOLP Index by Planning Reserve Margin Level

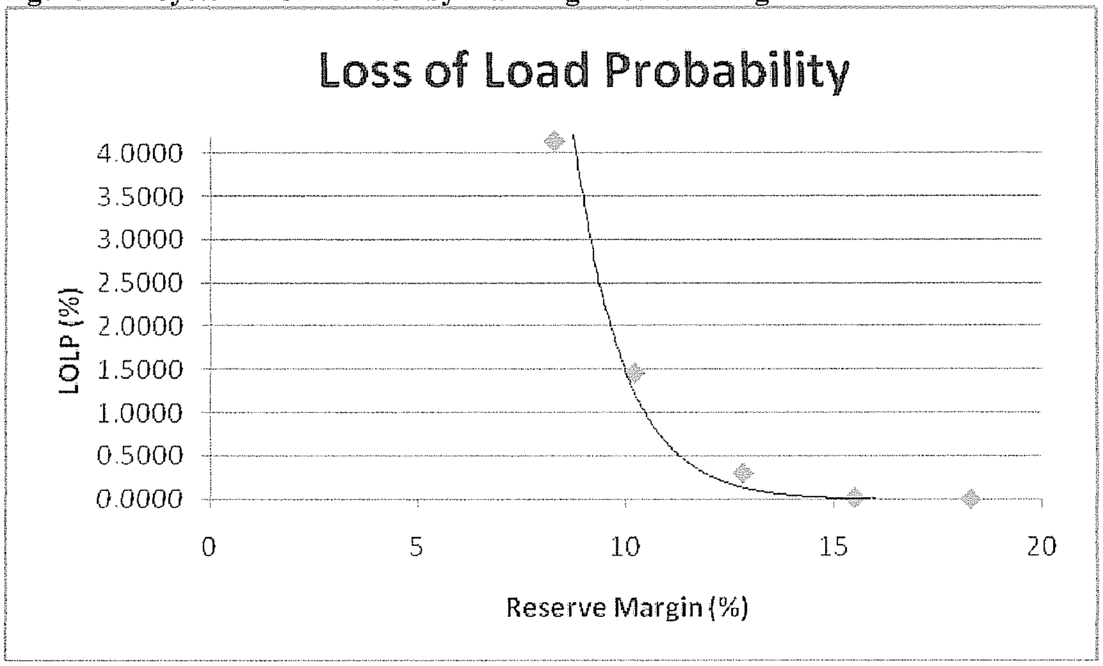
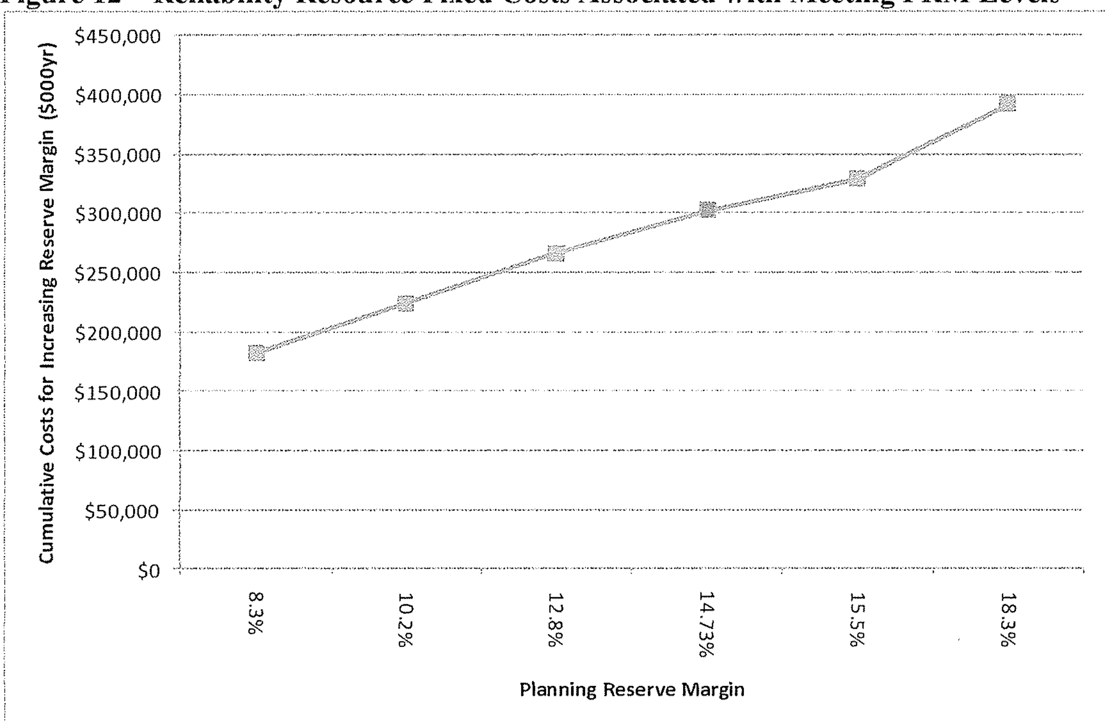


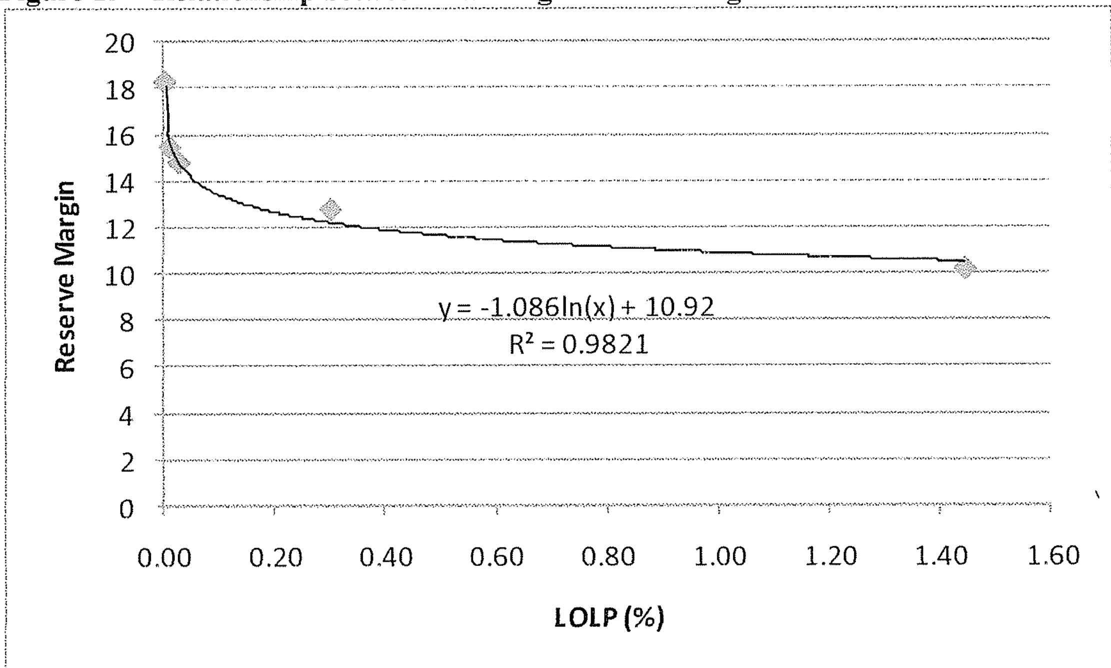
Figure 12 – Reliability Resource Fixed Costs Associated with Meeting PRM Levels



SELECTION OF A LOLP RELIABILITY TARGET

Traditionally, the long-term reliability planning standard has been a one-day in ten year loss of load criterion: 24 hours / (8760 hours x 10 years) = 0.027%. PacifiCorp has thus adopted this standard for determination of its PRM for IRP portfolio development.[6] Using a logarithmic functional form and regressing the PRM levels against the LOLP index values, yielded a PRM of 14.8% to achieve a one-day in ten year loss of load (Figure 13).

Figure 13 – Relationship between Planning Reserve Margin and LOLP



CAPACITY PLANNING RESERVE MARGIN DETERMINATION

As noted previously, the loss of load study does not incorporate the benefit of the Northwest Power Pool reserve sharing program. As a result, the 14.8% PRM requires a downward adjustment. Applying the 1.5% RMRG reserve sharing impact estimated by Ventyx for Public Service Company of Colorado results in an adjusted PRM of 13.3%. Rounding to 13% yields the PRM that PacifiCorp selected for its 2011 IRP portfolio development.

[6] Reliance on a one-in-ten loss of load criterion is being bolstered at the Federal level. The Federal Energy Regulatory Commission issued a Notice of Proposed Rulemaking in October 2010 approving a regional resource adequacy standard for Reliability*First* Corporation (RFC) based on a one-in-ten loss of load criterion. RFC is one of the nine North American Electric Reliability Corporation's electricity reliability councils, consisting of the former Mid-Atlantic Area Council (MAAC), the East Central Area Coordination Agreement (ECAR), and the Mid-American Interconnected Network (MAIN).

CONCLUSION

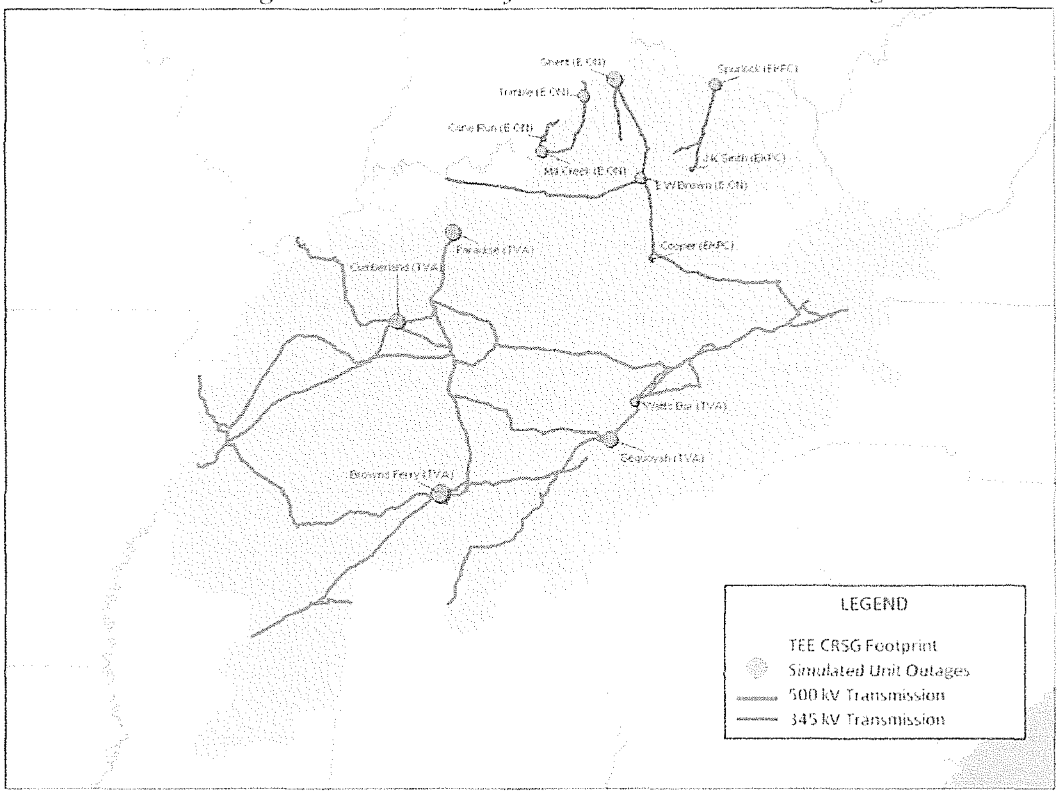
Based on the loss of load study and an out-of-model planning reserve margin adjustment to reflect reliability benefits from the Northwest Power Pool's reserve sharing program, PacifiCorp selected a 13% PRM for 2011 IRP portfolio development. PacifiCorp's previous PRM was 12%. This study incorporated a one-year snapshot of the transmission topology and loads & resources situation, targeting 2014 as the representative study year. Since the study focused on the PRM needed to meet firm load and sales obligations, it did not incorporate the reliability benefits of accessing off-system generation with non-firm transmission capacity.

PacifiCorp will continue to evaluate the reliability impact of different resource mixes using LOLP and Energy Not Served measures as part of its portfolio evaluation process.

Contingency Reserve Sharing Group
Certification of Deliverability

East Kentucky Power Cooperative (EKPC), E.ON U.S. (E.ON) and Tennessee Valley Authority (TVA) executed a contingency reserve sharing group agreement (TEE CRSG) that became effective on January 1, 2010. To assess the capability of the interconnected transmission systems of the three parties and the first-tier interconnected transmission systems to support such an agreement, a joint deliverability study was conducted prior to the beginning of the TEE CRSG operations. The finding of that study was that a contingency reserve sharing agreement between EKPC, E.ON, and TVA is deliverable over the interconnected transmission systems of the participating parties and the first-tier interconnected transmission systems, except for the EKPC J.S. Cooper Plant. Delivery of reserves for the loss of the Cooper Plant is conditional.

Figure 1 – Locations of Plants with Tested Unit Outages



The contingency reserve sharing agreement specified utilization of net MW capability of generating units as the basis for determining each company's reserve obligation. The deliverability study therefore used this as the basis for the analyses performed. The TEE CRSG Operating Committee has recently agreed to utilize gross MW capability rather than net MW capability. This change increases the Most Severe Single Contingency value for the TEE CRSG, and also changes the requirements of each company for most of the unit outage scenarios covered by the reserve sharing agreement. Due to this change in the agreement, the deliverability study has been updated to verify deliverability and to determine the revised values of Transmission Reliability Margin (TRM) to be allocated to the interfaces of the transmission systems of the three parties.

For this study update, the power flow cases that were used for the original study were updated. The updated set of cases was used to perform the same transfer analyses as in the original deliverability study.

The joint study team has determined through the findings of this study update that the contingency reserve sharing arrangement between EKPC, E.ON, and TVA -- including the change to providing reserves for gross MW capability of generating units -- remains deliverable over the interconnected transmission systems of the participating parties and the first-tier interconnected transmission systems, except for the EKPC J.S. Cooper plant. Delivery of reserves for the loss of the Cooper plant remains conditional. The study identified that the loss of generation at the J.S. Cooper plant (EKPC) combined with transmission contingencies, under the assumed modeled conditions, can lead to or exacerbate thermal overloads on the Alcalde – Elihu 161 kV line (E.ON), the Elza – Huntsville 161 kV line (TVA), and the Braytown-Huntsville 161 kV line (TVA). Operating guides remain necessary to address these scenarios *should they materialize in real time operations.*

To accommodate the CRSG agreement, sufficient capacity will be reserved on the interfaces and/or Flowgates in the form of TRM. All three parties use the Flowgate Methodology for calculating Available Flowgate Capability for each ATC Path. Each party will need to revise the calculation of the Short-term System Operator response (Operating Reserve actions) component of its TRM reservation on each Flowgate to reflect the revised obligations of the TEE CRSG. The transmission contract path ratings between the TEE CRSG participants are shown in Figure 2. The TRM to be reserved on each interface is determined by the maximum reserve obligations and are identified in Tables 1 and 2 below.

Figure 2 - Contract Path Ratings (MVA)

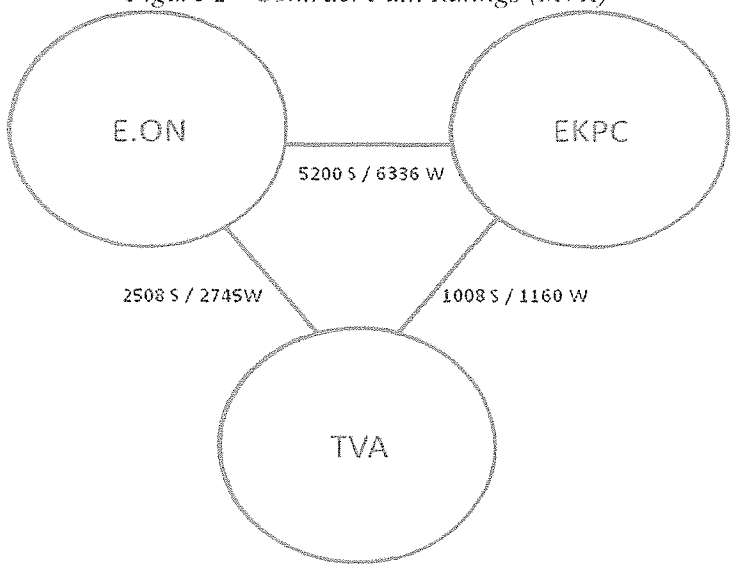


Table 1 – Interface TRM for Reserve Sharing (Jan. – May 2010)
(Prior to addition of Trimble County Unit 2)

Transfer Path	TRM (MW)
EKPC to E.ON	29
EKPC to TVA	100
E.ON to EKPC*	77
E.ON to TVA	212
TVA to EKPC*	378
TVA to E.ON	306

Table 2 – Interface TRM for Reserve Sharing (June 2010 and beyond)
(After addition of Trimble County Unit 2)

Transfer Path	TRM (MW)
EKPC to E.ON	55
EKPC to TVA	100
E.ON to EKPC*	77
E.ON to TVA	212
TVA to EKPC*	378
TVA to E.ON	571

* Delivery of reserves for the loss of the EKPC Cooper plant is conditional.

EKPC, E.ON, and TVA hereby certify deliverability as described above for the calendar year 2010.

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Date

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Understanding Cost-Effectiveness of Energy Efficiency Programs:

Best Practices, Technical Methods, and Emerging Issues for Policy-Makers

A RESOURCE OF THE NATIONAL ACTION PLAN FOR ENERGY EFFICIENCY

NOVEMBER 2008

This paper, *Understanding Cost-Effectiveness of Energy Efficiency Programs,* is provided to assist utility regulators, gas and electric utilities, and others in meeting the 10 implementation goals of the National Action Plan for Energy Efficiency's Vision to achieve all cost-effective energy efficiency by 2025.

This paper reviews the issues and approaches involved in considering and adopting cost-effectiveness tests for energy efficiency, including discussing each perspective represented by the five standard cost-effectiveness tests and clarifying key terms.

The intended audience for the paper is any stakeholder interested in learning more about how to evaluate energy efficiency through the use of cost-effectiveness tests. All stakeholders, including public utility commissions, city councils, and utilities, can use this paper to understand the key issues and terminology, as well as the various perspectives each cost-effectiveness test provides, and how the cost-effectiveness tests can be implemented to capture additional energy efficiency.

The Leadership Group of the National Action Plan for Energy Efficiency is committed to taking action to increase investment in cost-effective energy efficiency. *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers* was developed under the guidance of and with input from the Leadership Group. The document does not necessarily represent a consensus view and does not represent an endorsement by the organizations of Leadership Group members.

Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers is a product of the National Action Plan for Energy Efficiency and does not reflect the views, policies, or otherwise of the federal government. The role of the U.S. Department of Energy and U.S. Environmental Protection Agency is limited to facilitation of the Action Plan.

If this document is referenced, it should be cited as:

National Action Plan for Energy Efficiency (2008). *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers*. Energy and Environmental Economics, Inc. and Regulatory Assistance Project. <www.epa.gov/eeactionplan>

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List of Abbreviations and Acronyms

AEO	Annual Energy Outlook
Btu	British thermal unit
CCGT	combined cycle gas turbine
CDM	conservation and demand management
CEC	California Energy Commission
CFL	compact fluorescent light bulb
CO_2	*carbon dioxide*
DCR	debt-coverage ratio
DOE	U.S. Department of Energy
DR	demand response
DSM	demand-side management
EPA	U.S. Environmental Protection Agency
GHG	greenhouse gas
HP	horsepower
HVAC	heating, ventilation, and air conditioning
ICAP	installed capacity
IOU	investor-owned utility
IRP	integrated resource planning
kW	kilowatt
kWh	*kilowatt-hour*
LNG	liquefied natural gas
LSE	load serving entity
MMBtu	million Btu
MW	megawatt
MWh	megawatt-hour
NEBs	non-energy benefits
NO_x	nitrogen oxides
NPV	net present value
NTG	net-to-gross ratio
NWPCC	Northwest Power and Conservation Council
NYSERDA	New York State Energy Research and Development Authority
PACT	program administrator cost test (same as UCT)
PCT	participant cost test
PSE	Puget Sound Energy
RIM	ratepayer impact measure test
ROE	return on equity
RPS	renewable portfolio standard
SCE	Southern California Edison
SCT	societal cost test
SEER	Seasonal Energy Efficiency Ratio
SO_x	sulfur oxides
T&D	transmission and distribution
TOU	time of use
TRC	total resource cost test
TWh	terawatt-hour
UCAP	unforced capacity
UCT	utility cost test (same as PACT)
VOC	volatile organic compound
WACC	weighted average cost of capital

Acknowledgements

This technical issue paper, *Understanding Cost-Effectiveness of Energy Efficiency Programs,* is a key product of the Year Three Work Plan for the National Action Plan for Energy Efficiency. This work plan was developed based on Action Plan Leadership Group discussions and feedback expressed during and in response to the January 7, 2008, Leadership Group Meeting and the February 2008 Initial Draft Work Plan. A full list of Leadership Group members is provided in Appendix A.

With direction and comment by the Action Plan Leadership Group, the paper's development was led by Snuller Price, Energy and Environmental Economics, Inc., under contract to the U.S. Environmental Protection Agency (EPA). Additional preparation was performed by Eric Cutter and Rebecca Ghanadan of Energy and Environmental Economics, Inc.

Rich Sedano and Brenda Hausauer of the Regulatory Assistance Project supplied information on the use of cost-effectiveness tests by states and provided their expertise during the review and editing of the paper. Alison Silverstein also provided expertise during the review and editing of the paper.

EPA and the U.S. Department of Energy (DOE) facilitate the National Action Plan for Energy Efficiency. Key staff include Larry Mansueti (DOE Office of Electricity Delivery and Energy Reliability), Dan Beckley (DOE Office of Energy Efficiency and Renewable Energy), and Kathleen Hogan, Katrina Pielli, and Stacy Angel (EPA Climate Protection Partnership Division).

Eastern Research Group, Inc., provided copyediting, graphics, and production services.

Executive Summary

This paper, Understanding Cost-Effectiveness of Energy Efficiency Programs, reviews the issues and approaches involved in considering and adopting cost-effectiveness tests for energy efficiency, including discussing each perspective represented by the five standard cost-effectiveness tests and clarifying key terms. This paper is provided to assist organizations in meeting the 10 implementation goals of the National Action Plan for Energy Efficiency's Vision to achieve all cost-effective energy efficiency by 2025.

Improving energy efficiency in our homes, businesses, schools, governments, and industries—which consume more than 70 percent of the natural gas and electricity used in the country—is one of the most constructive, cost-effective ways to address the challenges of high energy prices, energy security and independence, air pollution, and global climate change. Despite these benefits and the success of energy efficiency programs in some regions of the country, energy efficiency remains critically underutilized in the nation's energy portfolio. It is time to take advantage of more than two decades of experience with successful energy efficiency programs, broaden and expand these efforts, and capture the savings that energy efficiency offers. Understanding energy efficiency cost-effectiveness tests and the various stakeholder perspectives each test represents is key to establishing the policy framework to capture these benefits.

This paper has been developed to help parties pursue the key policy recommendations and implementation goals of the National Action Plan for Energy Efficiency. The Action Plan was released in July 2006 as a call to action to bring diverse stakeholders together at the national, regional, state, or utility level, as appropriate, and foster the discussions, decision-making, and commitments necessary to take investment in energy efficiency to a new level. This paper directly supports the National Action Plan's Vision for 2025 implementation goal three, which encourages state agencies along with key stakeholders to establish cost-effectiveness tests for energy efficiency. This goal highlights the policy step to establish a process to examine how to define cost-effective energy efficiency practices that capture the long-term resource value of energy efficiency.

Evaluating the cost-effectiveness of energy efficiency is essential to identifying how much of our country's potential for energy efficiency resources will be captured. Based on studies, energy efficiency resources may be able to meet 50 percent or more of the expected load growth by 2025 (National Action Plan for Energy Efficiency, 2008). Defining cost-effectiveness helps energy efficiency compete with the broad range of other resource options in order for energy efficiency to get the attention and funding necessary to succeed.

In its simplest form, energy efficiency cost-effectiveness is measured by comparing the benefits of an investment with the costs. Five key cost-effectiveness tests have, with minor updates, been used for over 20 years as the principal approaches for energy efficiency program evaluation. These five cost-effectiveness tests are the participant cost test (PCT), the utility/program administrator cost test (PACT), the ratepayer impact measure test (RIM), the total resource cost test (TRC), and the societal cost test (SCT).

The key points from this paper include:

- There is no single best test for evaluating the cost-effectiveness of energy efficiency.

- Each of the cost-effectiveness tests provides different information about the impacts of energy efficiency programs from distinct vantage points in the energy system. Together, multiple tests provide a comprehensive approach.

- Jurisdictions seeking to increase efficiency implementation may choose to emphasize the PACT, which compares energy efficiency as a utility investment on a par with other resources.

- The most common primary measurement of energy efficiency cost-effectiveness is the TRC, followed closely by the SCT. A positive TRC result indicates that the program will produce a net reduction in energy costs in the utility service territory over the lifetime of the program. The distributional tests (PCT, PACT, and RIM) are then used to indicate how different stakeholders are affected. Historically, reliance on the RIM test has limited energy efficiency investment, as it is the most restrictive of the five cost-effectiveness tests.

There are a number of choices in developing the costs and benefits of energy efficiency that can significantly affect the cost-effectiveness results. Several major choices available to utilities, analysts, and policy-makers are described below.

- **Where in the process to apply the cost-effectiveness tests:** The choice of where to apply each cost-effectiveness test has a significant impact on the ultimate set of measures offered to customers. In general, there are three places to evaluate the cost-effectiveness test: at the "measure" level, the "program" level, and the "portfolio" level. Applying cost-effectiveness tests at the program or portfolio levels allows some non-cost-effective measures or programs to be offered as long as their shortfall is more than offset by cost-effective measures and programs.

- **Which benefits to include:** There are two main categories of avoided costs: energy-related and capacity-related. Energy-related avoided costs refer to market prices of energy, fuel costs, natural gas commodity prices, and other variable costs. Capacity-related avoided costs refer to infrastructure investments such as power plants, transmission and distribution lines, and pipelines. From an environmental point of view, saving energy reduces air emissions, including greenhouse gases (GHGs). Within each of these categories, policy-makers must decide which specific benefits are sufficiently known and quantifiable to be included in the cost-effectiveness evaluation.

- **Net present value and discount rates:** A significant driver of overall cost-effectiveness of energy efficiency is the discount rate assumption used to calculate the net present value (NPV) of the annual costs and benefits. Since costs typically occur upfront and savings occur over time, the lower the discount rate the more likely the cost-effectiveness result is to be positive. As each cost-effectiveness test portrays a specific stakeholder's view, each cost-effectiveness test should use the discount rate associated with its perspective. For a household, the consumer lending rate is used, since this is the debt cost that a private individual would pay to finance an energy efficiency investment. For a business firm, the discount rate is the firm's weighted average cost of capital, typically in the 10 to 12 percent range. However, commercial and industrial customers often demand payback periods of two years or less, implying a discount rate well in excess of 20 percent. The PACT, RIM, and TRC should reflect the utility weighted average cost of capital. The social discount rate (typically the lowest rate) should be used for the SCT to reflect the benefit to society over the long term.

- **Net-to-gross ratio (NTG):** The NTG can be a significant driver in the results of TRC, PACT, RIM, and SCT. The NTG adjusts the impacts of the programs so that they only reflect those energy efficiency gains that are the result of the energy efficiency program. Therefore, the NTG deducts energy savings that would have been achieved without the efficiency program (e.g., "free-riders") and increases savings for any "spillover" effect that occurs as an indirect result of the program. Since the NTG attempts to measure what customers would have done in the absence of the energy efficiency program, it can be difficult to determine precisely.

- **Non-energy benefits (NEBs):** Energy efficiency measures often have additional benefits (and costs) beyond energy savings, such as improved comfort, productivity, health, convenience and aesthetics. However, these benefits can be difficult to quantify. Some jurisdictions choose to include NEBs and costs in some of the cost-effectiveness tests, often focusing on specific issues emphasized in state policy.

- **GHG emissions:** There is increasing interest in valuing the energy efficiency's effect on reducing GHG emissions in the cost-effectiveness tests. The first step is to determine the quantity of avoided carbon dioxide (CO_2) emissions from the efficiency program. Once the amount of CO_2 reductions has been determined, its economic value can be calculated and added to the net benefits of the energy efficiency measures used to achieve the reductions. Currently, some jurisdictions use an explicit monetary CO_2 value in cost-benefit calculations and some do not.

- **Renewable portfolio standards (RPS):** The interdependence between energy efficiency and RPS goals is an emerging issue in energy efficiency. Unlike supply-side investments, energy efficiency, by reducing load, can reduce the amount of renewable energy that must be procured pursuant to RPS targets. This reduces RPS compliance cost, which is a benefit that should be considered in energy efficiency cost-effectiveness evaluation.

1: Introduction

Improving the energy efficiency of homes, businesses, schools, governments, and industries—which consume more than 70 percent of the natural gas and electricity used in the United States—is one of the most constructive, cost-effective ways to address the challenges of high energy prices, energy security and independence, air pollution, and global climate change. Mining this efficiency could help us meet on the order of 50 percent or more of the expected growth in U.S. consumption of electricity and natural gas in the coming decades, yielding many billions of dollars in saved energy bills and avoiding significant emissions of greenhouse gases and other air pollutants.[1]

Recognizing this large opportunity, more than 60 leading organizations representing diverse stakeholders from across the country joined together to develop the National Action Plan for Energy Efficiency. The Action Plan identifies many of the key barriers contributing to underinvestment in energy efficiency; outlines five policy recommendations for achieving all cost-effective energy efficiency; and offers a wealth of resources and tools for parties to advance these recommendations, including a Vision for 2025. As of November 2008, over 120 organizations have endorsed the Action Plan recommendations and made public commitments to implement them in their areas. Establishing cost-effectiveness tests for energy efficiency investments is key to making the Action Plan a reality.

1.1 Background on Cost-effectiveness Tests

The question of how to define the cost-effectiveness of energy efficiency investments is a critical issue to address when advancing energy efficiency as a key resource in meeting future energy needs. How cost-effectiveness is defined substantially affects how much of our nation's efficiency potential will be accessed and whether consumers will benefit from the lower energy costs and environmental impacts that would result. The decisions on how to define cost-effectiveness or which tests to use are largely made by state utility commissions and their utilities, and with critical input from consumers and other stakeholders. This paper is provided to help facilitate these discussions.

Cost-effectiveness in its simplest form is a measure of whether an investment's benefits exceed its costs. Key differences among the cost-effectiveness tests that are currently used include the following:

- The stakeholder perspective of the test. Is it from the perspective of an energy efficiency program participant, the organization offering the energy efficiency program, a non-participating ratepayer, or society in general? Each of these perspectives represents a valid viewpoint and has a role in assessing energy efficiency programs.

- The key elements included in the costs and the benefits. Do they reflect avoided energy use, incentives for energy efficiency, avoided need for new generation and new transmission and distribution, and avoided environmental impacts?

- The baseline against which the cost and benefits are measured. What costs and benefits would have been realized absent investment in energy efficiency?

The five cost-effectiveness tests commonly used across the country are listed below:

- Participant cost test (PCT).
- Program administrator cost test (PACT).[2]
- Ratepayer impact measure test (RIM).
- Total resource cost test (TRC).
- Societal cost test (SCT).

These cost-effectiveness tests are used differently in different states. Some states require all of the tests, some require no specific tests, and others designate a primary test. Table 1-1 provides a quick overview of which tests are used in which states. Chapter 5 presents more information and guidelines on the use of the cost-effectiveness tests by the states.

Table 1-1. Cost-Effectiveness Tests in Use by Different States as Primary or Secondary Consideration

PCT	PACT	RIM	TRC	SCT
AR, FL, GA, HI, IA, IN, MN, VA	AT, CA, **CT**, HI, IA, IN, MN, NO, NV, OR, **UT**, VA, **TX**	AR, DC, **FL**, GA, HI, IA, IN, KS, MN, NH, VA	AR, **CA**, CO, CT, DE, FL, GA, HI, IL, IN, KS, **MA**, MN, **MO**, MT, **NH**, **NM**, NY, UT, VA	**AZ**, CO, GA, HI, IA, IN, MW, **ME**, **MN**, MT, NV, OR, VA, **VT**, **WI**

Source: Regulatory Assistance Project (RAP) analysis

Note: Boldface indicates the primary cost-effectiveness test used by each state

1.2 About the Paper

This paper examines the five standard cost-effectiveness tests that are regularly used to assess the cost-effectiveness of energy efficiency, the perspectives each test represents, and how states are currently using the tests. It also discusses how the tests can be used to provide a more comprehensive picture of the cost-effectiveness of energy efficiency as a resource. Use of a single cost-effectiveness test as a primary cost-effectiveness test may lead to an efficiency portfolio that does not balance the benefits and costs between stakeholder perspectives. Overall, using all five cost-effectiveness tests provides a more comprehensive picture than using any one test alone.

Paper Objective

After reading this paper, the reader should be able to understand the perspective represented by each of the five standard cost tests, understand that all five tests provide a more comprehensive picture than any one test alone, have clarity around key terms and definitions, and use this information to shape how the cost-effectiveness of energy efficiency programs is treated.

This paper was prepared in response to a need identified by the Action Plan Leadership Group (see Appendix A) for a practical discussion of the key considerations and technical terms involved in defining cost-effectiveness and establishing which cost-effectiveness tests to use in developing an energy efficiency program portfolio. The Leadership Group offers this reference to program designers and policy-makers who are involved in adopting and implementing cost-effectiveness tests for evaluating efficiency investments.

This paper supports the *National Action Plan for Energy Efficiency Vision for 2025: A Framework for Change* (National Action Plan for Energy Efficiency, 2008). This Vision establishes a long-term aspirational goal to achieve all cost-effective energy efficiency by 2025 and outlines 10 goals for implementing the Leadership Group's recommendations (see Figure 1-1). This paper directly supports the Vision's third implementation goal, which encourages states and key stakeholders to establish cost-effectiveness tests for energy efficiency. This goal encourages applicable state agencies, along with key stakeholders, to establish a process to examine how to define cost-effective energy efficiency practices that capture the long-term resource value of energy efficiency.

Figure 1-1. Ten Implementation Goals of the *National Action Plan for Energy Efficiency Vision for 2025: A Framework for Change*

Goal One:	Establishing Cost-Effective Energy Efficiency as a High-Priority
Goal Two:	Developing Processes to Align Utility and Other Program Administrator Incentives Such That Efficiency and Supply Resources Are on a Level Playing Field
Goal Three:	Establishing Cost-Effectiveness Tests
Goal Four:	Establishing Evaluation, Measurement, and Verification Mechanisms
Goal Five:	Establishing Effective Energy Efficiency Delivery Mechanisms
Goal Six:	Developing State Policies to Ensure Robust Energy Efficiency Practices
Goal Seven:	Aligning Customer Pricing and Incentives to Encourage Investment in Energy Efficiency
Goal Eight:	Establishing State of the Art Billing Systems
Goal Nine:	Implementing State of the Art Efficiency Information Sharing and Delivery Systems
Goal Ten:	Implementing Advanced Technologies

1.3 Structure of the Paper

This paper walks the reader through the basics of cost-effectiveness tests and the perspectives they represent, issues in determining the costs and benefits to include in the cost-effectiveness tests, emerging issues, how states are currently using cost-effectiveness tests, and guidelines for policy-makers.

The key chapters of the paper are the following:

- Chapter 2. This chapter discusses the five standard cost-effectiveness tests and their application in four utility best practice programs.
- Chapter 3. This chapter briefly describes the interpretation of each test and presents a calculation of each cost-effectiveness test using an example residential program from Southern California Edison.

- Chapter 4. This chapter presents the key factors and issues in the determination of an energy efficiency program's cost-effectiveness. It also discusses key emerging issues that are shaping energy efficiency programs, including the impact greenhouse gas (GHG) reduction targets and renewable portfolio standards (RPS) may have on energy efficiency programs.

- Chapter 5. This chapter gives guidelines and examples for policy-makers to consider when choosing which cost-effectiveness test(s) to emphasize, and summarizes of the use of the cost-effectiveness tests in each state.

- Chapter 6. This chapter describes the calculation of each cost-effectiveness test in detail, as well as the key considerations when reviewing and using cost-effectiveness tests and the pros and cons of each test in relation to increased efficiency investment.

- Appendix C. This chapter gives further detail on the four example programs included in Chapter 2. It also describes how the cost-effectiveness test results were calculated for each program.

1.4 Development of the Paper

Understanding Cost-Effectiveness of Energy Efficiency Programs is a product of the Year Three Work Plan for the National Action Plan for Energy Efficiency. With direction and comment by the Action Plan Leadership Group (see Appendix A for a list of group members), the paper's development was led by Snuller Price, Eric Cutter, and Rebecca Ghanadan of Energy and Environmental Economics, Inc., under contract to the U.S. Environmental Protection Agency and the U.S. Department of Energy. Chapter 5 was authored by Rich Sedano and Brenda Hausauer of the Regulatory Assistance Project, under contract to the U.S. Department of Energy.

1.5 Notes

1 See the *National Action Plan for Energy Efficiency Vision for 2025. A Framework for Change* (National Action Plan for Energy Efficiency, 2008).

2 The program administrator cost test, or PACT, was originally named the utility cost test (UCT). As program management has expanded to government agencies, nonprofit groups, and other parties, the term "program administrator cost test" has come into use, but the computations are the same. This document refers to the UCT/PACT as the "PACT" for simplicity. See Section 6.2 for more information on the test.

2: Getting Started: Overview of the Cost-Effectiveness Tests

This chapter provides a brief overview of the cost-effectiveness tests used to evaluate energy efficiency measures and programs. All the cost-effectiveness tests use the same fundamental approach in comparing costs and benefits. However, each test is designed to address different questions regarding the cost-effectiveness of energy efficiency programs.

2.1 Structure of the Cost-Effectiveness Tests

Each of the tests provides a different kind of information about the impacts of energy efficiency programs from different vantage points in the energy system. On its own, each test provides a single stakeholder perspective. Together, multiple tests provide a comprehensive approach for asking: Is the program effective overall? Is it balanced? Are some costs or incentives too high or too low? What is the effect on rates? What adjustments are needed to improve the alignment? Each test contributes one of the aspects necessary to understanding these questions and answering them.

The basic structure of each cost-effectiveness test involves a calculation of the total benefits and the total costs in dollar terms from a certain vantage point to determine whether or not the overall benefits exceed the costs. A test is positive if the benefit-to-cost ratio is greater than one, and negative if it is less than one. Results are reported either in net present value (NPV) dollars (method by difference) or as a ratio (i.e., benefits/costs). Table 2-1 outlines the basic approach underlying cost-effectiveness tests.

Table 2-1. Basic Approach for Calculating and Representing Cost-Effectiveness Tests

Net Benefits (Difference)	Net Benefits$_a$ (dollars)	=	NPV $\sum$ benefits$_a$ (dollars) - NPV $\sum$ costs$_a$ (dollars)
Benefit-Cost Ratio	Benefit-Cost Ratio$_a$	=	$\dfrac{\text{NPV} \sum \text{benefits}_a \text{ (dollars)}}{\text{NPV} \sum \text{costs}_a \text{ (dollars)}}$

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects

Note: "NPV" refers to the net present value of benefits and costs. See Section 4.6.

> Cost-effectiveness test results compare relative benefits and costs from different perspectives. A benefit-cost ratio above 1 means the program has positive net benefits. A benefit-cost ratio below 1 means the costs exceed the benefits. A first step in analyzing programs is to see which cost-effectiveness tests are produce results above or below 1.

2.2 The Five Cost-Effectiveness Tests and Their Origins

Currently, five key tests are used to compare the costs and benefits of energy efficiency and demand response programs. These tests all originated in California. In 1974, the Warren Alquist Act established the California Energy Commission (CEC) and specified cost-effectiveness as a leading resource planning principle. In 1983, California's *Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs* manual developed five cost-effectiveness tests for evaluating energy efficiency programs. These approaches, with minor updates, continue to be used today and are the principal approaches used for evaluating energy efficiency programs across the United States.[1]

Table 2-2 summarizes the five tests in terms of the questions they help answer and the key elements of the comparison.

Table 2-2. The Five Principal Cost-Effectiveness Tests Used in Energy Efficiency

Test	Acronym	Key Question Answered	Summary Approach
Participant cost test	PCT	Will the participants benefit over the measure life?	Comparison of costs and benefits of the customer installing the measure
Program administrator cost test	PACT	Will utility bills increase?	Comparison of program administrator costs to supply-side resource costs
Ratepayer impact measure	RIM	Will utility rates increase?	Comparison of administrator costs and utility bill reductions to supply-side resource costs
Total resource cost test	TRC	Will the total costs of energy in the utility service territory decrease?	Comparison of program administrator and customer costs to utility resource savings
Societal cost test	SCT	Is the utility, state, or nation better off as a whole?	Comparison of society's costs of energy efficiency to resource savings and non-cash costs and benefits

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

2.3 Cost-Effectiveness Test Results in Best Practice Programs

Illustrating cost-effectiveness test calculations, Table 2-3 shows benefit-cost ratio results from four successful energy efficiency programs from across the country.[2] The Southern California Edison (SCE) Residential Energy Efficiency Incentive Program provides customer incentives for efficient lighting and appliances. Avista's results are for its Regular Income Portfolio, which includes a variety of programs targeted to residential users. Puget Sound Energy's Commercial/Industrial Retrofit Program encourages commercial customers to install cost- and energy-efficient equipment, adopt energy-efficient designs, and use energy-efficient operations at their facilities. Finally, the National Grid's MassSAVE residential program provides residential in-home audits and incentives for comprehensive whole-house improvements.

All the programs presented have been determined to be cost-effective by the relevant utilities[3] and regulators. Nevertheless, the results of the five cost-effectiveness tests vary significantly for each program. Furthermore, the result of each cost-effectiveness test across the four programs *is also quite different. (Puget Sound Energy is the only utility for which all five cost-effectiveness* tests are positive.) The test results show a range of values that reflect the program designs and the individual choices made by the program administrators and policy-makers for their evaluation. As later chapters discuss, both the individual tests *and* the relationships between test results offer useful information for assessing programs.

Table 2-3. Summary of Cost-effectiveness Test Results for Four Energy Efficiency Programs

Test	Southern California Edison Residential Energy Efficiency Incentive Program	Avista Regular Income Portfolio	Puget Sound Energy Commercial/ Industrial Retrofit Program	National Grid MassSAVE Residential
	Benefit-Cost Ratio			
PCT	7.14	3.47	1.72	8.81
PACT	9.91	4.18	4.19	2.64
RIM	0.63	0.85	1.15	0.54
TRC	4.21	2.26	1.90	1.73
SCT	4.21	2.26	1.90	1.75

Source: E3 analysis; see Appendix C.

Note: The calculation of each cost-effectiveness test varies slightly by jurisdiction. See Appendix C for more details.

The choice of cost-effectiveness test depends on the policy goals and circumstances of a given program and state. Multiple tests yield a more comprehensive assessment than any test on its own.

2.4 Notes

1 The California standard practice manual was first developed in February 1983. It was later revised and updated in 1987–88 and 2001; a Correction Memo was issued in 2007. The 2001 California SPM and 2007 Correction Memo can be found at <http://www.cpuc.ca.gov/PUC/energy/electric/Energy+Efficiency/EM+and+V/>.

2 The cost-effectiveness test results of each program are described further in Appendix C.

3 "Utility" refers to any organization that delivers electric and gas utility services to end users, including investor-owned, cooperatively owned, and publicly owned utilities.

3: Cost-Effectiveness Test Review—Interpreting the Results

This chapter discusses the benefit and cost components included in each cost-effectiveness test, and profiles how a residential lighting and appliance incentive program fares under each test. It also provides an overview of important considerations when using cost-effectiveness tests.

Overall, the results of all five cost-effectiveness tests provide a more comprehensive picture than the use of any one test alone. The TRC and SCT cost tests help to answer whether energy efficiency is cost-effective overall. The PCT, PACT, and RIM help to answer whether the selection of measures and design of the program is balanced from participant, utility, and non-participant perspectives respectively. Looking at the cost-effectiveness tests together helps to characterize the attributes of a program or measure to enable decision making, to determine whether some measures or programs are too costly, whether some costs or incentives are too high or too low, and what adjustments need to be made to improve distribution of costs and benefits among stakeholders. The scope of the benefit and cost components included in each test is summarized in Table 3-1 and Table 3-2.

The broad categories of costs and benefits included in each cost-effectiveness test are consistent across all regions and applications. However, the specific components included in each test may vary across different regions, market structures, and utility types. Transmission and distribution investment may be considered deferrable through energy efficiency in some areas and not in others. Likewise, the TRC and SCT may consider just natural gas or electricity resource savings in some cases, but also include co-benefits of other savings streams (such as water and fuel oil) in others. Considerations regarding the application of each cost-effectiveness test and which cost and benefit components to include are the subject of Chapter 5.

3.1 Example: Southern California Edison Residential Energy Efficiency Program

The Southern California Edison (SCE) Residential Energy Efficiency Incentive Program provides customer incentives for efficient lighting and appliances (not including HVAC). It is part of a statewide mass market efficiency program that coordinates marketing and outreach efforts. This section summarizes how to calculate cost-effectiveness for each cost-effectiveness test using the SCE Residential Energy Efficiency Incentive Program as an example. Calculations for three additional programs from other utilities are evaluated in Appendix C.

Table 3-1. Summary of Benefits and Costs Included in Each Cost-Effectiveness Test

Test	Benefits	Costs
PCT	*Benefits and costs from the perspective of the customer installing the measure*	
	• Incentive payments • Bill savings • Applicable tax credits or incentives	• Incremental equipment costs • Incremental installation costs
PACT	*Perspective of utility, government agency, or third party implementing the program*	
	• Energy-related costs avoided by the utility • Capacity-related costs avoided by the utility, including generation, transmission, and distribution	• Program overhead costs • Utility/program administrator incentive costs • Utility/program administrator installation costs
RIM	*Impact of efficiency measure on non-participating ratepayers overall*	
	• Energy-related costs avoided by the utility • Capacity-related costs avoided by the utility, including generation, transmission, and distribution	• Program overhead costs • Utility/program administrator incentive costs • Utility/program administrator installation costs • Lost revenue due to reduced energy bills
TRC	*Benefits and costs from the perspective of all utility customers (participants and non-participants) in the utility service territory*	
	• Energy-related costs avoided by the utility • Capacity-related costs avoided by the utility, including generation, transmission, and distribution • Additional resource savings (i.e., gas and water if utility is electric) • Monetized environmental and non-energy benefits (see Section 4.9) • Applicable tax credits (see Section 6.4)	• Program overhead costs • Program installation costs • Incremental measure costs (whether paid by the customer or utility)
SCT	*Benefits and costs to all in the utility service territory, state, or nation as a whole*	
	• Energy-related costs avoided by the utility • Capacity-related costs avoided by the utility, including generation, transmission, and distribution • Additional resource savings (i.e., gas and water if utility is electric) • Non-monetized benefits (and costs) such as cleaner air or health impacts	• Program overhead costs • Program installation costs • Incremental measure costs (whether paid by the customer or utility)

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects

Table 3-2. Summary of Benefits and Costs Included in Each Cost-Effectiveness Test

Component	PCT	PACT	RIM	TRC	SCT
Energy- and capacity-related avoided costs		Benefit	Benefit	Benefit	Benefit
Additional resource savings				Benefit	Benefit
Non-monetized benefits					Benefit
Incremental equipment and installation costs	Cost			Cost	
Program overhead costs		Cost	Cost	Cost	Cost
Incentive payments	Benefit	Cost	Cost		
Bill savings	Benefit		Cost		

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects

Note: Incentive payments include any equipment and installation costs paid by the program administrator

3.1.1 Overview of the Program

The SCE Residential Energy Efficiency Incentive Program resulted in costs of:

- $3.5 million in administration and marketing for SCE.
- $15.5 million in customer incentives, direct installation, and upstream payments combined for SCE.
- $41.1 million in measure installation costs for customers (before incentives).

The reduced energy consumption achieved as a result of the program resulted in:

- $188 million in avoided cost savings to the utility.
- $278 million in bill savings to the customers (and reduced revenue to SCE).
- Reduced nitrogen oxides (NO_x), PM_{10},[1] and carbon dioxide (CO_2) emissions.

The costs and savings are presented on a "net" basis, after the application of the net-to-gross ratio (NTG). The determination of the NTG is described in Section 4.7. The benefits and costs of the SCE program are presented in Table 3-3 and Table 3-4. Together, these two tables provide the key parameters for employing individual cost-effectiveness tests, as well as the calculations leading to each test are discussed in turn.

Table 3-3. SCE Residential Energy Efficiency Incentive Program Benefits

Net Benefit Inputs		
Resource savings	Units	$
Energy (MWh)	2,795,290	$ 187,904,906
Peak demand (kW)	55,067	—
Total resource savings		$ 187,904,906
Participant bill savings		$ 278,187,587
Emission savings	Tons	
NO_x	421,633	
PM_{10}	203,065	
CO_2	1,576,374	

Source: E3 analysis, see Appendix C

Table 3-4. SCE Residential Energy Efficiency Incentive Program Costs

Cost Inputs	
Program overhead	
Program administration	$ 898,548
Marketing and outreach	$ 559,503
Rebate processing	$ 1,044,539
Other	$ 992,029
Total program administration	$ 3,494,619
Program incentives	
Rebates and incentives	$ 1,269,393
Direct installation costs	$ 564,027
Upstream payments	$ 13,624,460
Total incentives	$ 15,457,880
Total program costs	$ 18,952,499
Net measure equipment and installation	$ 41,102,993

Source: E3 analysis, see Appendix C.

3.1.2 Cost-Effectiveness Test Results Overview

The results of each of the five cost-effectiveness tests for 2006 (based on the information in the fourth quarter 2006 SCE filing) are presented in Table 3-5[2] A first level assessment shows that the SCE program is very cost-effective for the participant (PCT), the utility (PACT), and the region as a whole (TRC). The program will reduce average energy bills, and a RIM below 1.0 suggests that the program will increase customer rates. Greater detail on the application of each of these cost-effectiveness tests is provided below.

Table 3-5. Summary of Cost-Effectiveness Test Results ($Million)

Test	Cost	Benefits	Ratio	Result
PCT	$41	$294	7.14	Bill savings are more than seven times greater than customer costs.
PACT	$19	$188	9.91	The value of saved energy is nearly 10 times greater than the program cost.
RIM	$297	$188	0.63	The reduced revenue and program cost is greater than utility savings.
TRC	$45	$188	4.21	Overall benefits are four times greater than the total costs.
SCT	$45	$188	4.21	Same as the TRC, as no additional benefits are currently included in the SCT in California.

Source: E3 analysis, see Appendix C

3.1.3 Calculating the PCT

The PCT assesses the costs and benefits from the perspective of the customer installing the measure. Overall, customers received $294 million in benefits (derived from utility program incentives and bill savings from reduced energy use). The incremental costs to customers were $41 million. This yields an overall net benefit of $252 million and a benefit-cost ratio of 7.14. The PCT shows that bill savings are seven times customer costs—a cost-effective program for the participant. PCT calculation terms from the SCE program data are presented in Table 3-6.

Table 3-6. Participant Cost Test for SCE Residential Energy Efficiency Program

PCT Calculations		
	Benefits	Costs
Program overhead		
Program incentives	$ 15,457,880	
Measure costs		$ 41,102,993
Energy savings		
Bill savings	$ 278,187,587	
Monetized emissions		
Non-energy benefits		
Total	$ 293,645,466	$ 41,102,993
Net benefit	$252,542,473	
Benefit-cost ratio	7.1	

Source: E3 analysis, see Appendix C

3.1.4 Calculating the PACT

The PACT calculates the costs and benefits of the program from the perspective of SCE as the utility implementing the program. SCE's avoided costs of energy are $188 million (energy savings). Overhead and incentive costs to SCE are $19 million. These figures yield an overall net benefit of $169 million and a benefit-to-cost ratio of 9.91. The PACT result shows that the value of saved energy is nearly 10 times greater than the program cost: high cost-effectiveness from the perspective of the utility's administration of the program. Table 3-7 shows the breakdown of costs and benefits yielding the positive PACT result.

Table 3-7. Program Administrator Cost Test for SCE Residential Efficiency Program

PACT Calculations		
	Benefits	Costs
Program overhead		$ 3,494,619
Program incentives		$ 15,457,880
Measure costs		
Energy savings (net)	$ 187,904,906	
Bill savings		
Monetized emissions (net)	$ 0	
Non-energy benefits		
Total	$ 187,904,906	$ 18,952,499
Net benefit	$168,952,407	
Benefit-cost ratio	9.91	

Source: E3 analysis, see Appendix C

3.1.5 Calculating the RIM

The RIM examines the potential impact the energy efficiency program has on rates overall. The net benefits are the avoided cost of energy (same as PACT). The net costs include the overhead and incentive costs (same as PACT), but also include utility lost revenues from customer bill savings. The result of the SCE program is a loss of $109 million and a benefit-to-cost ratio of 0.63. This result suggests that, all other things being equal, the hypothetical impact of the program on rates would be for rates to increase. However, in practice, non-participants are unaffected until rates are adjusted through a rate case or a decoupling mechanism. In the long term, energy efficiency may reduce the capacity needs of the system; this can lead to either higher or lower rates to non-participants depending on the level of capital costs saved. Energy efficiency can be a lower-cost investment than other supply-side resources to meet customer demand, thereby keeping rates lower than they otherwise would be. (This is discussed in more detail in Section 3.2.2.) Thus it is important to recognize the RIM as examining the potential impacts on rates, but also recognizing that a negative RIM does not necessarily mean that rates will actually increase. Section 6.3 discusses impacts over time in greater detail. Table 3-8 breaks down the costs and benefits included in the RIM.

Table 3-8. Ratepayer Impact Measure for SCE Residential Energy Efficiency Program

RIM Calculations		
	Benefits	Costs
Program overhead		$ 3,494,619
Program incentives		$ 15,457,880
Measure costs		
Energy savings (net)	$ 187,904,906	
Bill savings (net)		$ 278,187,587
Monetized emissions (net)	$ 0	
Non-energy benefits		
Total	$ 187,904,906	$ 297,140,085
Net benefit	($109,235,180)	
Benefit-cost ratio	0.63	

Source: E3 analysis, see Appendix C

3.1.6 Calculating the TRC

The TRC reflects the total benefits and costs to all customers (participants and non-participants) in the SCE service territory. The key difference between the TRC and the PACT is that the former does not include program incentives, which are considered zero net transfers in a regional perspective (i.e., costs to the utility and benefits to the customers). Instead, the TRC includes the net measure costs of $41 million. Net benefits in the TRC are the avoided costs of energy, $188 million. The regional perspective yields an overall benefit of $143 million and a benefit-to-cost ratio of 4.21. In California, the TRC includes an adder that internalizes the benefits of avoiding the emission of NO_x, CO_2, sulfur oxides (SO_x), and volatile organic compounds (VOCs). The adder is incorporated into energy savings (and not broken out as a separate category).[3] In many jurisdictions, the avoided costs are based on a market price that is presumed to implicitly include emissions permit costs and an explicit calculation of permit costs for regulated emissions is not made. The TRC shows that overall benefits are four times greater than total costs (a lower benefits-to-cost ratio than the PACT and PCT, but still positive overall). Table 3-9 shows the costs and benefits included in the TRC calculation.

Table 3-9. Total Resource Cost Test for SCE Residential Energy Efficiency Program

TRC Calculations		
	Benefits	Costs
Program overhead		$ 3,494,619
Program incentives		
Measure costs (net)		$ 41,102,993
Energy savings (net)	$ 187,904,906	
Bill savings		
Monetized emissions (net)	(included in energy savings above)	
Non-energy benefits		
Total	$ 187,904,906	$ 44,597,612
Net benefit	$143,307,294	
Benefit-cost ratio	4.21	

Source: E3 analysis, see Appendix C

3.1.7 Calculating the SCT

In California, the avoided costs of emissions are included directly in energy savings. These benefits are included in both TRC and SCT values, and as a result, their test outputs are the same (see Table 3-10).

Table 3-10. Societal Cost Test for SCE Residential Energy Efficiency Program

SCT Calculations		
	Benefits	Costs
Program overhead		$ 3,494,619
Program incentives		
Measure costs (net)		$ 41,102,993
Energy savings (net)	$ 187,904,906	
Bill savings		
Monetized emissions (net)	(included in energy savings above)	
Non-energy benefits (net)	$ 0	
Total	$ 187,904,906	$ 44,597,612
Net benefit	$143,307,294	
Benefit-cost ratio	4.21	

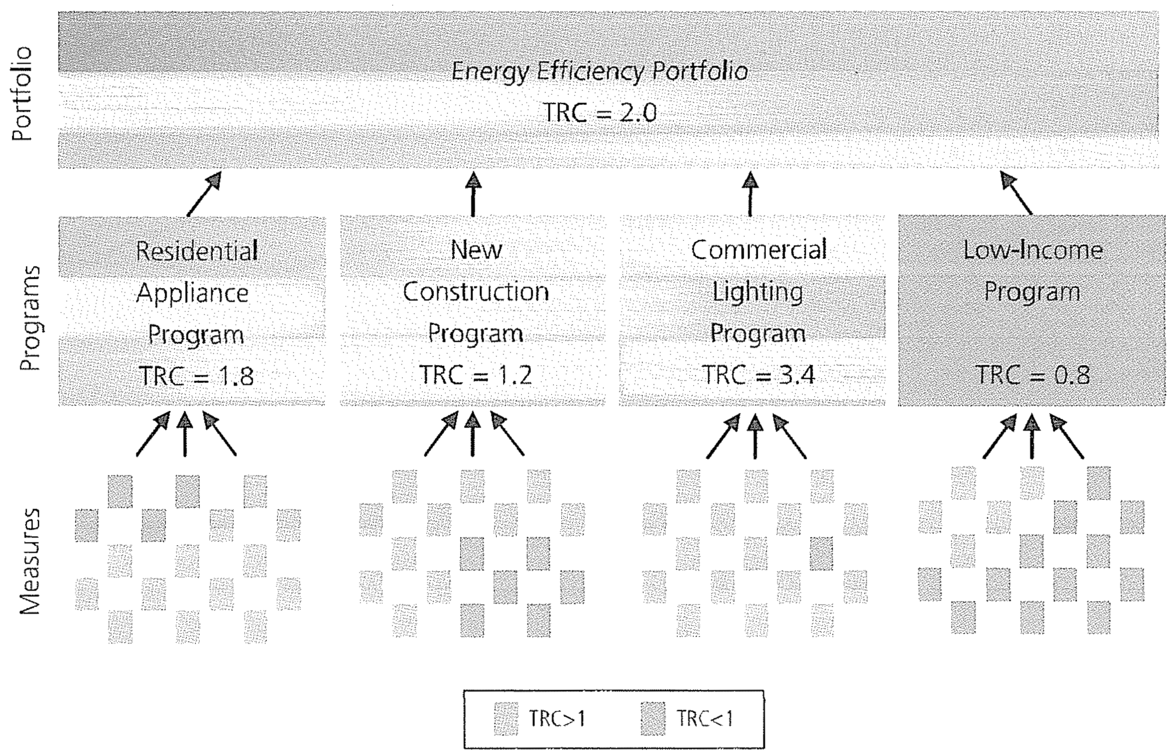
Source: E3 analysis, see Appendix C

3.2 Considerations When Using Cost-Effectiveness Tests

3.2.1 Application of Cost-Effectiveness Tests

Cost-effectiveness tests can be applied at different points in the design of the energy efficiency portfolio, and the choice of when to apply each cost-effectiveness test has a significant impact on the ultimate set of measures offered to customers. In general, there are three places to evaluate the cost-effectiveness test: the "measure" level, the "program" level, and at the "portfolio" level. Evaluating cost-effectiveness at the measure level means that each individual component of a utility program must be cost-effective. Evaluation at the utility program level means that collectively the measures under a program must be cost-effective, but some measures can be uneconomical if there are other measures that more than make up for them. Evaluating cost-effectiveness at the portfolio level means that all of the programs taken together must be cost-effective, but individual programs can be positive or negative. Figure 3-1 illustrates a hypothetical portfolio in which cost-effectiveness is evaluated at the portfolio level, allowing some measures and programs that are not cost-effective even as the overall portfolio remains positive. If cost-effectiveness were evaluated at a measure level, those measures in red—the low-income program—could be eliminated as not cost-effective and would not be offered to customers.

Figure 3-1. Hypothetical Cost-Effectiveness at Measure, Program, and Portfolio Levels



Applying cost-effectiveness tests at the measure level is the most restrictive. With this approach, the analyst or policy-maker is explicitly or implicitly emphasizing the cost-effectiveness rather than the total energy savings of the efficiency portfolio. In contrast, applying cost-effectiveness tests at the portfolio level allows utilities greater flexibility to experiment with different strategies and technologies and results in greater overall energy savings, though at the expense of a less cost-effective portfolio overall. California applies the cost-effectiveness tests at the portfolio level specifically to allow and encourage the implementation of emerging technology and market transformation programs that promote important policy goals but do not themselves pass the TRC or PCT.

Strictly applying cost-effectiveness at the measure or even the program level can often result in the need for specific exceptions. At the measure level, variations in climate, building vintage, building type and end use may affect the cost-effectiveness of a measure. For marketing clarity, a rebate might be provided service-territory-wide even if some eligible climate zones and customer types are not cost-effective since differentiating among customer types may complicate the advertising message and make the program less effective (the program designers make sure the measure is cost-effective overall). At the program level, some programs—such as low-income programs—generally need higher incentive levels and marketing focus and may not be cost-effective, but are desired in the overall portfolio for social equity and other policy reasons. Similarly, some programs, such as those for emerging technologies or Home Performance with ENERGY STAR, ramp up slowly over time and typically do not achieve cost-effectiveness within the first three years, but do provide energy efficiency benefits. Also, the program and portfolio approaches make it easier to include supporting programs such as informational campaigns that raise overall awareness and complement other programs, but may not be cost-effective on a stand-alone basis.

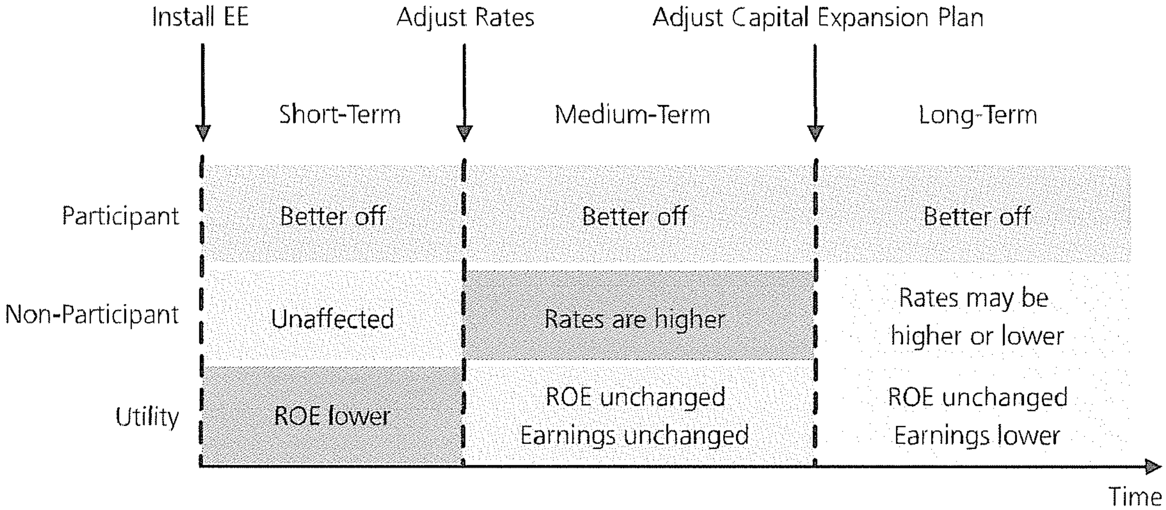
Summing up the benefits of multiple measures at the program level may require some adjustment for what are known as "interactive effects" between related measures. Interactive effects occur when multiple measures installed together affect each other's impacts. When measures affect the same end use, their combined effect when implemented together may be less than the sum of each measure's individually estimated impact. An insulation and air conditioning measure may each save 500 kilowatt-hours (kWh) individually, but less than 1,000 kWh when installed together. Alternatively, some measures may have additional benefits when other end uses are also present (i.e., "interactive effects"). For example, replacing incandescent bulbs with compact fluorescent light bulbs (CFLs) also reduces cooling loads in buildings with air conditioning.

3.2.2 Impacts Over Time of the Distribution Tests

Cost-effectiveness tests are evaluated on a life-cycle basis; however, they do not show the way impacts vary or adjust over time. As a result, it is important to recognize the ways in which program impacts may vary over time in order to properly interpret cost-effectiveness test results. For example, the RIM estimates the impact of the energy efficiency program on non-participants. Yet non-participants are actually unaffected until rates are adjusted through a rate case or a decoupling mechanism. Figure 3-2 illustrates the distributional impacts on the participant, non-participant, and utility over time in the common test-result case where energy efficiency has a PCT above 1 and a RIM below 1.[4]

Consider three time periods from the point at which the energy efficiency measure is first installed: the short term, medium term, and long term. The short term is defined as the period between installing the energy efficiency and adjusting the rate levels. The medium term begins once rates are adjusted and lasts until the change in energy efficiency results in an adjustment to the capital plan. The long term begins once the capital expansion plan has been changed.

Figure 3-2. Timeline of Distributional Impacts When PCT > 1 and RIM < 1



From a participant perspective, because the PCT is above 1.0, the participant is better off once an investment in energy efficiency is made, as the utility bill is lower than it would have been throughout the time horizon. In the short term, the non-participant is indifferent since rates have not been adjusted.[5] However, because the RIM is below 1.0, the utility is saving less than the drop in revenue from the participant and will therefore have lower return on equity (ROE), or debt-coverage ratio (DCR) for a public utility, compared to the case without energy efficiency. Note that for utilities with decoupling mechanisms or annual fuel cost adjustments, some or all of the rate impact may be felt before the next regular rate case cycle.

In the medium term, rates will be increased to hit the target ROE or DCR and the utility will be indifferent to the energy efficiency. This rate increase, however, affects the non-participating customers who have the same consumption as they otherwise would have, but now face higher rates. Finally, in the long term, energy efficiency may reduce the capacity needs of the system, as the capital expansion requirements of the utility are reduced. The long-term rate impact will depend on the level of fixed capital costs included in the avoided costs to value the energy savings. If the avoided costs include the long-term capacity cost savings realized through energy efficiency, a RIM ratio below 1.0 would indicate that rates will be higher in the long term. In many cases, however, avoided costs are based primarily on market prices, which tend to represent a short-term view. Thus, it may be that energy efficiency will meet load growth at a lower cost than that of alternative utility investments, and rates will be lower than they otherwise would have been even if the RIM ratio is below 1.0. To the extent that less capital is needed, earnings will be lower for the utility since the utility will be smaller relative to the no-efficiency case. However, ROE or DCR will be unchanged in the long term since rates will be adjusted periodically based on the target ROE or DCR.

3.3 Notes

[1] PM10 is particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.

[2] Calculations of the cost tests were made by the paper's authors using a simplified analysis tool. This serves to illustrate the concepts, but may not match exactly what each utility has reported based on their own analysis.

[3] The inclusion of the environmental adder in the TRC is an effort to directly internalize the externalities of environmental impacts into California's primary cost test, which is the TRC (see Section 5.1.1).

[4] More detailed analysis of impacts over time can be evaluated with the National Action Plan for Energy Efficiency's Energy Efficiency Benefits Calculator, using a set of assumptions that can be modified to fit a particular utility. See <http://www.epa.gov/cleanenergy/energy-programs/napee/resources/calculator.html>.

[5] If the load forecasts used in rate-making are adjusted to reflect projected efficiency savings, rates may increase in the short term as well

4: Key Drivers in the Cost-Effectiveness Calculation

In addition to the cost-effectiveness tests themselves, there are a number of choices in developing the costs and benefits that can significantly affect the cost-effectiveness results. This chapter describes some of the major choices available to analysts and policy-makers; it is a resource and reference for identifying and better understanding the variations in possible terms and approaches and developing a more robust understanding of possible evaluation techniques and their trade-offs. Because energy efficiency programs vary in different energy sectors and have different embedded savings and cost values, the variations on these terms are considerable. Thus, this chapter cannot be a step-by-step guide of all possible conditions.

Issues covered in this chapter include:

- Which benefits to include in each cost-effectiveness test.
- Whether to emphasize accuracy or transparency.
- Which methodology to use to forecast future benefits of energy and capacity savings.
- What time period to consider when assessing costs and benefits.
- Whether to determine demand- and supply-side resource requirements in the same analysis (true "integrated resource planning").
- Whether to use a public, non-proprietary data set to develop the benefits, or rely on proprietary forecasts and estimates.
- Which discount rates to use in NPV analysis.
- Whether to incorporate non-energy benefits (NEBs) and costs in the calculation.
- What NTG to use.
- Whether to include CO_2 emissions reductions in the analysis.
- Whether to include RPS procurement costs in the analysis.

Ultimately, the types of costs, benefits, and methodology used depend on the policy goals. This chapter outlines the key terms that will need to be addressed in weighing and evaluating efficiency programs. It also provides a discussion of key factors in applying cost-effectiveness test terms.

4.1 Framework for Cost-Effectiveness Evaluation

The typical approach for quantifying the benefits of energy efficiency is to forecast long-term "avoided costs," defined as costs that would have been spent if the energy efficiency savings measure had not been put in place. For example, if an electric distribution utility expects to purchase energy at a cost of $70 per megawatt-hour (MWh) on behalf of customers, then $70/MWh is the value of reduced purchases from energy efficiency. In addition, the utility may not have to purchase as much system capacity (ICAP or UCAP),[1] make as many upgrades to distribution or transmission systems, buy as many emissions offsets, or incur as many other costs. All such cost savings resulting from efficiency are directly counted as "avoided cost" benefits. In addition to the directly counted benefits, the state regulatory commission or governing councils may request that the utility account for indirect cost savings that are not priced by the market (e.g., reduced CO_2 emissions). For additional information on avoided costs, refer to the National Action Plan's *Guide to Resource Planning with Energy Efficiency* (National Action Plan for Energy Efficiency, 2007b [Chapter 2]).

4.2 Choosing Which Benefits to Include

There are two main categories of avoided costs: energy-related and capacity-related avoided costs. Energy-related avoided costs involve market prices of energy, losses, natural gas commodity prices, and other benefits associated with energy production such as reduced air emissions and water usage. Capacity-related avoided costs involve infrastructure investments such as power plants, transmission and distribution lines, pipelines, and liquefied natural gas (LNG) terminals. Environmental benefits make up a third category of benefits that are frequently included in avoided costs. Saving energy reduces air emissions including GHGs, and saving capacity addresses land use and siting issues such as new transmission corridors and power plants.

Table 4-1 lists the range of avoided cost components that may be included in avoided cost benefits calculations for electricity and natural gas energy efficiency programs. The most commonly included components (and which comprise the majority of avoided costs) for electric utilities are both energy and capacity. Natural gas utilities will typically include energy and may or may not include the capacity savings.[2] Depending on the utility and the focus of the state regulatory commission or governing council, others may also be included.

Table 4-1. Universe of Energy and Capacity Benefits for Electricity and Natural Gas

Electricity Energy Efficiency	
Energy Savings	Capacity Savings
Market purchases or fuel and operation and maintenance costs	Capacity purchases or generator construction
System losses	System losses (peak load)
Ancillary services related to energy	Transmission facilities
Energy market price reductions	Distribution facilities
Co-benefits in water, natural gas, fuel oil, etc.	Ancillary services related to capacity
Air emissions	Capacity market price reductions
Hedging costs	Land use
Natural Gas Energy Efficiency	
Energy Savings	Capacity Savings
Market purchases at city gate	Extraction facilities
Losses	Pipelines
Air emissions	Cold weather action/pressurization activities
Market price reductions	Storage facilities
Co-benefits in water, natural gas, fuel oil, etc.	LNG terminals
Hedging costs	

Note: More detail on each of these components can be found in Chapter 3 of the Action Plan's *Guide to Resource Planning with Energy Efficiency* (National Action Plan for Energy Efficiency, 2007b).

Most states select a subset to analyze from within this "universe" of benefits when evaluating energy efficiency. No state considers them all. The most important factor in choosing the components is to inform the decisions on energy efficiency given the policy backdrop and situation of the state. As an example of how calculations may be adopted to specific conditions, California chose to include market price reduction effects in evaluating energy efficiency programs during the California Energy Crisis. Similarly, large capital projects such as LNG terminals or power plants, or a focus on GHGs or local environment, might lead to emphasizing these components over others. There may be diminishing value to detailed analysis of small components of the avoided cost that will not change the fundamental decisions.

4.3 Level of Complexity When Forecasting Avoided Costs

Within the avoided cost framework, there are many ways to estimate the benefits. The approach may be as simple as estimating the fixed and variable costs of displaced generation and using them as the avoided costs (as is done in Texas). An alternative approach is to use a more sophisticated integrated resource planning (IRP) approach that simultaneously evaluates both supply- and demand-side investments. This IRP analysis may include a simulation of the utility system with representation of all of the generation, transmission constraints, and loads over time (for example, see the Northwest Power Planning and Conservation Council 5th Power Plan[3] or PacifiCorp Integrated Resource Planning[4]). This requires a much more complex set of analysis tools, but provides more information on the right timing, desired quantity, and value of energy efficiency with respect to the existing utility system and its expected future loads.

In general, more sophisticated and accurate estimates of benefits are better. However, other considerations include the following:

- Availability of resources needed to complete the analysis and stakeholders' review before adoption may be a problem in states without intervener compensation.
- Time taken to complete the analysis with sophisticated IRP approaches could delay implementation of energy efficiency. The regulatory landscape in many states is littered with IRP proceedings that are contentious and have taken years to complete.
- Transparency of the approach to a broad set of stakeholders is also valued and may be easier to achieve without sophisticated models to achieve broader support.

4.4 Forecasts of Avoided Costs

Depending on the utility type and market structure in a region, there are a number of methodology options for developing avoided natural gas and electricity costs. The first approach is to use forward and futures market data, which are publicly available and transparent to all stakeholders. However, energy efficiency is likely to have a life longer than available market prices, and a supplemental approach will also be needed to estimate long-term costs.

The second approach is to use public or private long-run forecast of electricity and natural gas costs, such as those produced by the Department of Energy's Energy Information Agency and many state agencies (utilities participating in wholesale markets will also have proprietary forward market forecasts to inform trading activities).

The third approach is to develop simple long run estimates of future electricity value by choosing a typical "marginal resource" such as a combined cycle natural gas plant and forecasting its variable costs into the future. A more sophisticated variation would be to incorporate production simulation modeling of the electricity system into this analysis. Overall, it is important to understand the underlying assumptions of the forecasting approach and assess whether or not these assumptions are appropriate for the intended purpose. Table 4-2 *summarizes avoided costs approaches* by *utility* type *and each is described in more detail* below.

Table 4-2. Approaches to Valuing Avoided Energy and Capacity Costs by Utility Type

Utility Type	Near-Term Analysis (i.e., Market Data Available)	Long-Term Analysis (i.e., No Market Data Available)
Distribution electric or natural gas utility	Current forward market prices of energy and capacity	Long-term forecast of market prices of energy and capacity
Electric vertically integrated utility	Current forward market prices of energy and capacity *or* Expected production cost of electricity and value of deferring generation projects	Long-term forecast of market prices of energy and capacity *or* Expected production cost of electricity and value of deferring generation projects

4.4.1 Market Data

For utilities that are tightly integrated into the wholesale energy market, forward market prices provide a good basis for establishing avoided costs. If the utility is buying electricity, energy efficiency reduces the need to purchase electricity. If the utility can sell excess electricity, *energy savings enables additional sales, resulting in incremental revenue. In either case,* the market price is the per kWh value of energy efficiency. Forward market electricity prices are publicly available through services such as Platt's "Megawatt Daily," which surveys wholesale electricity brokers. This data is typically available extending three or four years into the future depending on the market.

The market price is also a good approach for natural gas utilities. The NYMEX futures market for natural gas provides market prices as far as 12 years in advance by month.[5] The market currently has active trading daily over the next three to five years. The NYMEX market also includes basis swaps that provide the price difference between Henry Hub and most delivery points in the United States.[6] Some analysts hesitate to use market data such as NYMEX beyond the period of active trading for fear that low volume of trading creates liquidity problems and prices that are not meaningful. While more liquid markets provide more rigor in the prices, *the less liquid long-term markets are still available for trading and are therefore unbiased* estimates of future market prices and may still be the best source of data.

Market prices provide a relatively simple, transparent, and readily accessible basis for quantifying avoided costs. On the other hand, market prices tend to be influenced primarily by current market conditions and variable operating costs, particularly in the near term. Market prices alone may not adequately represent long-term and/or fixed operating costs. The production simulation and proxy plant approaches described below provide alternative approaches that address long-term fixed costs.

4.4.2 Production Simulation Models

For self-resourced electric utilities that do not have wholesale market access or actively trade electricity, a "production simulation" forecast may be the best approach to forecast energy costs. A production simulation model is a software tool that performs system dispatch decisions to serve load at least cost, subject to constraints of transmission system, air permitting, and other operational parameters. The operating cost of the "marginal unit" in each hour or time period is used to establish the avoided cost of energy. The downside of production simulation models is that they are complex, rely on sophisticated algorithms that can appear as a "black box" to stakeholders, and have to be updated when market prices of inputs such as natural gas change. In addition, these types of models can have difficulty predicting market prices since the marginal energy cost is based on production cost, rather than supply and demand interactions in a competitive electricity market. If production simulation produces prices that differ from those actually seen in the market, energy efficiency can end up facing a cost hurdle that differs from the hurdles faced by supply-side resources. Long-term natural gas forecasts also often rely on production simulation to model regional supply, demand, and transportation dynamics and estimate the equilibrium market prices.

4.4.3 Long-Run Marginal Cost and the "Proxy Plant"

Developing a "proxy plant" is an alternative to production simulation approaches and may be used when market data is not available or appropriate. Under this approach, a fixed hypothetical plant is used as a proxy for the resources that will be built to meet incremental load.[7] Selecting the proxy-plant, the construction costs, financial assumptions, and operating characteristics are all assessed from its characteristics. As an example, the variable costs of a combined cycle natural gas plant may be used as a proxy for energy costs. The annual fixed cost of a combustion turbine may be used as a proxy for capacity costs. Several methods can be used to allocate fixed costs, adjust the variable operating costs, or otherwise shape the costs of the plant(s) across different time-of-use (TOU) periods. These methods include applying market price or system load shapes, loss of load probabilities, or marginal heat rates to vary prices by TOU. Another commonly used method is the peaker methodology, which uses an allocation of the capacity costs associated with peaking resources (typically combustion turbines) and the marginal system energy cost by hour (system lambda) to estimate avoided electricity costs in each hour or TOU period. These costs are then used to estimate the costs of the energy and capacity in the avoided costs calculations. The proxy plant approach is more transparent and understandable to many stakeholders (particularly in comparison to production simulation). The proxy plant approach may be used in conjunction with market data, to estimate costs for the periods beyond the time horizons when existing market data are available.

4.4.4 Proprietary and Public Forecasts

The easiest approach for a utility to develop long-term avoided costs may be to use its own internal forecast of market prices. This approach provides estimates of avoided cost that are closely linked to the utility operations. However, the methodology may be confidential since utilities involved in procuring electricity or natural gas on the market may not to reveal their expectations of future prices publicly. Therefore, the use of internal forecasts can significantly limit the stakeholder review process for evaluation of energy efficiency programs.

Public forecasts of avoided costs may also be used to develop a more open process for energy efficiency evaluation and planning. California, Texas, the Northwest Power Planning Council, Ontario, and others use a non-proprietary methodology. An open process allows non-utility stakeholders to evaluate and comment on the methodology, thereby increasing the confidence that the analysis is fair. This approach also makes it possible for energy efficiency contractors to evaluate the cost-effectiveness of proposed energy efficiency upgrades. Unfortunately, this open process may diverge from internal forecasts and introduce some discrepancy between the publicly adopted numbers and those actually used by utilities in resource planning and procurement decisions. States balance these concerns and generally commit to one path or the other.

Policy-makers may also rely on existing publicly available forecasts of electricity or natural gas. The most universal source of forecasts is the Annual Energy Outlook (AEO), provided by the Department of Energy's Energy Information Agency.[8] This public forecast provides regional long-term forecasts of electricity and natural gas. In addition to the AEO, state energy agencies or regional groups may provide their own independent forecasts, which may include sensitivity analysis. Some parties, however, view publicly developed forecasts with some skepticism, as they may be seen as being overly influenced by political considerations or the compromises necessary to gain wide support in a public process.

4.4.5 Risk Analysis

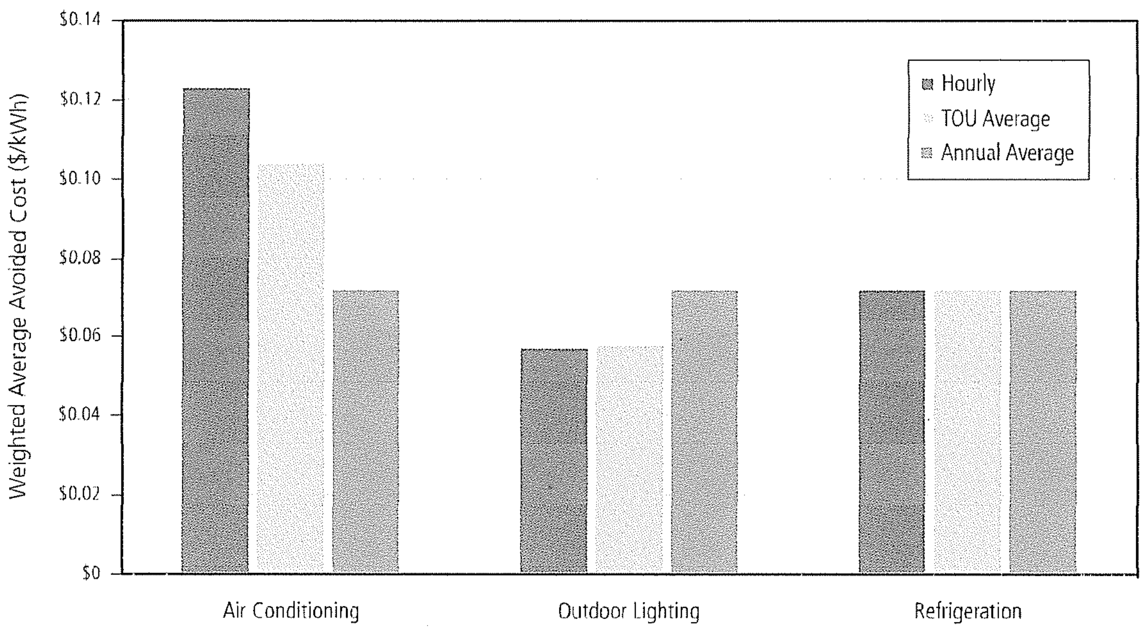
Electricity and natural gas prices are quite volatile and subject to cyclical ups and downs. In reducing load, energy efficiency also reduces a utility's exposure to fluctuating market prices. This provides an option or hedge value that can be quantified with risk analysis, but which is omitted when a single forecast of avoided costs is used.

Increasingly, utilities have used scenario and risk analysis to assess the benefits of different investment options under a range of future scenarios. One of the simpler approaches is to compare the cost-effectiveness results under multiple scenarios, using a high, expected, and low energy price forecast for example. More advanced techniques, such as Monte Carlo simulation, may be used to evaluate the performance of various resource plans under a wide range of possible outcomes.

4.5 Area- and Time-Specific Marginal Costs

For all of the forecasting approaches for avoided costs, the analyst must decide the level of disaggregation by area and time used in developing the forecasts. The marginal costs of electricity can vary significantly hour to hour and both electricity and natural gas prices vary by area and time of year. Similarly, the load reductions provided by energy efficiency measures also vary by season and time of day. Figure 4-1 shows the differences that can result when using hourly, TOU, and annual average avoided costs for different end uses, based on a study of air conditioning, outdoor lighting, and refrigeration end uses in California. The significance of using either TOU or average annual costs is highly dependent on the end use and demand/cost characteristics of the region in question. In California, the decision to use hourly avoided costs was made in order to appropriately value air conditioning energy efficiency.[9] This approach almost doubles the value of air conditioning measures relative to a flat annual average assessment of avoided cost (~$0.12/kWh vs. ~$0.07). In the case of other end uses, such as outdoor lighting efficiency, there is very little difference between hourly and TOU costs for end uses that operate evenly within a 24-hour period (e.g., refrigeration), there is no difference in method.

Figure 4-1. Implication of Time-of-Use on Avoided Costs



Source: California Proceeding on Avoided Costs of Energy Efficiency, R.04-04-025.

Another consideration of time-dependent avoided cost analysis is the need to correctly evaluate the tradeoffs between different types of energy efficiency measures. Hourly avoided costs are highly detailed, capturing the cost variance within and across major time periods. Annual average costs ignore the timing of energy savings. In the example above, using an annual average method, CFLs and outdoor lighting efficiency would receive the same value as air conditioning energy efficiency, while in actuality air conditioning energy efficiency is much more *valuable to the system overall because it reduces the peak load significantly. The use of hourly* avoided costs in this case reveals the large potential avoided cost value of air conditioning savings relative to other efficiency measures.

4.6 Net Present Value and Discount Rates

A significant driver of overall cost-effectiveness of energy efficiency is the discount rate assumption. Each cost-effectiveness test compares the NPV of the annual costs and benefits over the life of an efficiency measure or program. Typically, energy efficiency measures require an upfront investment, while the energy savings and maintenance costs accrue over several years. The calculation of the NPV requires a discount rate assumption, which can be different for the stakeholder perspective of each cost-effectiveness test.

As each perspective portrays a specific stakeholder's view, each perspective comes with its own discount rate. The five cost-effectiveness tests are listed in Table 4-3, along with the appropriate discount rate and an illustrative value. Using the appropriate discount rate is essential for correctly calculating the net benefits of an investment in energy efficiency.

Table 4-3. The Use of Discount Rates in Cost-Effectiveness Tests

Tests and Perspective	Discount Rate Used	Illustrative Value	Present Value of $1 a Year for 20 Years*	Today's Value of the $1 Received in Year 20
PCT	Participant's discount rate	10%	$8.51	$0.15
RIM	Utility WACC	8.5%	$9.46	$0.20
PACT	Utility WACC	8.5%	$9.46	$0.20
TRC	Utility WACC	8.5%	$9.46	$0.20
SCT	Social discount rate	5%	$12.46	$0.38

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

* This value is the same as not having to purchase $1 of electricity per year for 20 years.

Three kinds of discount rates are used, depending on which test is being calculated. For the PCT, the discount rate of an individual or business is used. For a household, this is taken to be the consumer lending rate, since this is the debt cost that a private individual would pay to finance an energy efficiency investment. It is typically the highest discount rate used in the cost-effectiveness tests. However, since there are potentially many different participants, with very different borrowing rates, it can be difficult to choose a single appropriate discount rate. Based on the current consumer loan market environment, a typical value may be in the 8 to 10 percent range (though a credit card rate might be much higher). For a business firm, the discount rate is the firm's weighted average cost of capital (WACC). In today's capital market environment, a typical value would be in the 10 to 12 percent range—though it can be as high as 20 percent, depending on the firm's credit worthiness and debt-equity structure. Businesses may also assume higher discount rates if they perceive several attractive investment opportunities as competing for their limited capital dollars. Commercial and industrial customers can have payback thresholds of two years or less, implying a discount rate well in excess of 20 percent.

For the SCT, the social discount rate is used. The social discount rate reflects the benefit to society over the long term, and takes into account the reduced risk of an investment that is spread across all of society, such as the entire state or region. This is typically the lowest discount rate. For example, California uses a 3 percent real discount rate (~5 percent nominal) in evaluating the cost-effectiveness of the Title 24 Building Standards.

Finally, for the TRC, RIM, or PACT, the utility's average cost of borrowing is typically used as the discount rate. This discount rate is typically called the WACC and takes into account the debt and equity costs and the proportion of financing obtained from each. The WACC is typically between the participant discount rate and the social discount rate. For example, California currently uses 8.6 percent in evaluating the investor-owned utility energy efficiency programs.

Using these illustrative values for each cost-effectiveness test, the third column of Table 4-3 shows the value of receiving $1 per year for 20 years from each perspective. This is analogous to the value of not having to purchase $1 of electricity per year. From a participant perspective assuming a 10 percent discount rate, this stream is worth $8.51; from a utility perspective, it is worth $9.46; and from a societal perspective, it is worth $12.46. The effect of the discount rate increases over time. The value today of the $1 received in the 20th year ranges from $0.15 from the participant perspective to $0.38 in the societal perspective, more than twice as much. Since the present value of a benefit decreases more over time with higher discount rates, the choice of discount rate has a greater impact on energy efficiency measures with longer expected useful lives.

4.7 Establishing the Net-to-Gross Ratio

A key requirement for cost benefit analysis is estimating the NTG. The NTG adjusts the cost-effectiveness results so that they only reflect those energy efficiency gains that are attributed to, and are the direct result of, the energy efficiency program in question. It gives evaluators an estimate of savings achieved as a direct result of program expenditures by removing savings that would have occurred even absent a conservation program. Establishing the NTG is critical to understanding overall program success and identifying ways to improve program performance. For more information on NTG in the context of efficiency program evaluation, see Chapter 5 of the National Action Plan for Energy Efficiency's *Model Energy Efficiency Program Impact Evaluation Guide* (National Action Plan for Energy Efficiency, 2007c).

Gross energy impacts are the changes in energy consumption and/or demand that result directly from program-related actions taken by energy consumers that are exposed to the program. Estimates of gross energy impacts always involve a comparison of changes in energy use over time among customers who installed measures versus some baseline level of usage.

Net energy impacts are the percentage of the gross energy impact that is attributable to the program. The NTG reduces gross energy savings estimates to reflect three types of adjustments:

- Deduction of energy savings that would have been achieved even without a conservation program.
- Deduction of energy savings that are not actually achieved in real world implementation.
- Addition of energy savings that occur as an indirect result of the conservation program.

Key factors addressed through the NTG are:

- **Free riders.** A number of customers take advantage of rebates or cost savings available through conservation programs even though they would have installed the efficient equipment on their own. Such customers are commonly referred to as "free riders."
- **Installation rate.** In many cases the customer does not ultimately install the equipment. In other cases, efficient equipment that is installed as part of an energy conservation program is later bypassed or removed by the customer. This is common for CFL programs.

- **Persistence/failure.** A certain percentage of installed equipment can be expected to fail or be replaced before the end of its useful life. Such early failure reduces the achieved savings as compared to pre-installation savings estimates.

- **Rebound effect.** Some conservation measures may result in savings during certain periods, but increase energy use before or after the period in which the savings occur. In addition, customers may use efficiency equipment more often due to actual or perceived savings.

- **Take-back effect.** A number of customers will use the reduction in bills/energy to increase their plug load or comfort by adjusting thermostat temperatures.

- **Spillover.** Spillover is the opposite of the free rider effect: customers that adopt efficiency measures because they are influenced by program-related information and marketing efforts, though they do not actually participate in the program.

4.8 Codes and Standards

Another way to encourage energy efficiency is to adopt increasingly strict codes and standards for energy use in buildings and appliances. This process is occurring in parallel with energy efficiency programs in most states, as each approach has its advantages and disadvantages. Codes and standards can be adopted for the state as a whole and do not demand the same level of state or utility funding as incentive programs. They do, on the other hand, impose regulatory and compliance costs on businesses and residents. Codes and standards generally involve a more complicated and potentially contentious legislative process than utility energy efficiency programs overseen by regulatory agencies. They also present enforcement challenges; local planning departments often do not have the staff, budget, or expertise to focus on state regulations related to energy use.

Increasingly strict codes and standards effectively raise the baseline that efficiency measures are compared against over time. This will reduce the energy savings and net benefits of efficiency measures, either by reducing the estimated savings or increasing the NTG.

4.9 Non-Energy Benefits and Costs

Conservation measures often have additional benefits beyond energy savings. These benefits include improved comfort, health, convenience, and aesthetics and are often referred to as non-energy effects (to include costs as well as benefits) or NEBs. None of the five cost-effectiveness tests explicitly recognizes changes in NEBs. Unless specifically cited, databases and studies generally exclude NEBs.

Examples of NEBs include:

- **From the customer perspective,** increased comfort, air quality, and convenience. For example, a demand response event that turns off air conditioning can reduce comfort and be a “cost” to the customer. Conversely, participants who gain improved heating and insulation can experience increased comfort, gaining an overall benefit.

- **From the utility perspective,** NEBs have been shown to reduce the number of shut-off notices issued or bill complaints received, particularly in low-income communities.

- **From a societal perspective,** efficiency programs can provide regional benefits in increased community health and improved aesthetics. On a larger scale, energy efficiency also reduces reliance on imported energy sources and provides national security benefits.

Studies attempting to estimate the value of NEBs are limited. Such studies often rely on participant surveys, which are designed to indicate their willingness to pay for NEBs or comparative valuation of various NEBs. Other studies rely on statistical analysis of survey data to estimate or "reveal" participant preferences toward NEBs. Both survey and statistical methods have significant limitations, and it is difficult to account for changing preferences across different income levels, cultural backgrounds, and household types. When values are not available, the judgment of regulators or program managers may be used. Examples of accounting for NEBs include decreasing costs or increasing benefits by a fixed percentage in the cost-effectiveness tests. To date, more emphasis has been placed on including NEBs than on non-energy costs. Nevertheless, as NEBs are incorporated in cost-effectiveness evaluation, non-energy costs should be evaluated on an equivalent basis. Examples of non-energy costs include reduced convenience and increased disposal or recycling costs.

4.10 Incentive Mechanisms

An area of growing interest in the application of cost-effectiveness tests is in establishing incentive mechanisms for utility efficiency programs. There exist two natural disincentives for utilities to invest in energy efficiency programs. First, energy efficiency reduces sales, which puts upward pressure on rates and can affect utility earnings. Second, utilities make money through a return on their capital investments or rate base. The financial disincentives for utilities are discussed thoroughly in the National Action Plan for Energy Efficiency's paper *Aligning Utility Incentives with Energy Efficiency Investment* (National Action Plan for Energy Efficiency, 2007a).

To address the reduced earnings from energy efficiency, states are increasingly exploring incentive mechanisms that allow a utility to earn a return on energy efficiency expenditures similar to the return on invested capital. The intent is to give the utility an equal (or greater) financial incentive to invest in energy efficiency as compared to traditional utility infrastructure.

The cost-effectiveness test results are increasingly being used as a metric to measure the incentive payment to the utility, based on the performance of the energy efficiency program. However, as discussed previously, no single cost-effectiveness test captures all of the goals of the efficiency program. Therefore, some states, such as California, have developed "weighting" approaches that combine the results of the cost-effectiveness tests. California has established a Performance Earnings Basis that is based on two-thirds of the TRC portfolio net benefits result and one-third of the PACT portfolio net benefits result. An incentive is then paid based on the utilities' combined results using this metric if the utilities' portfolio of savings meets or exceeds the utility commission's established energy savings goals.

When the cost-effectiveness tests are used in the payment of shareholder incentives, there will be additional scrutiny on the input assumptions and key drivers in the calculation. With this additional pressure, transparency and stakeholder review of the methodology becomes more important. Finally, the cost-effectiveness tests' use and their weights must be considered with care to align the utility objectives with the goals of the energy efficiency policy.

4.11 Greenhouse Gas Emissions

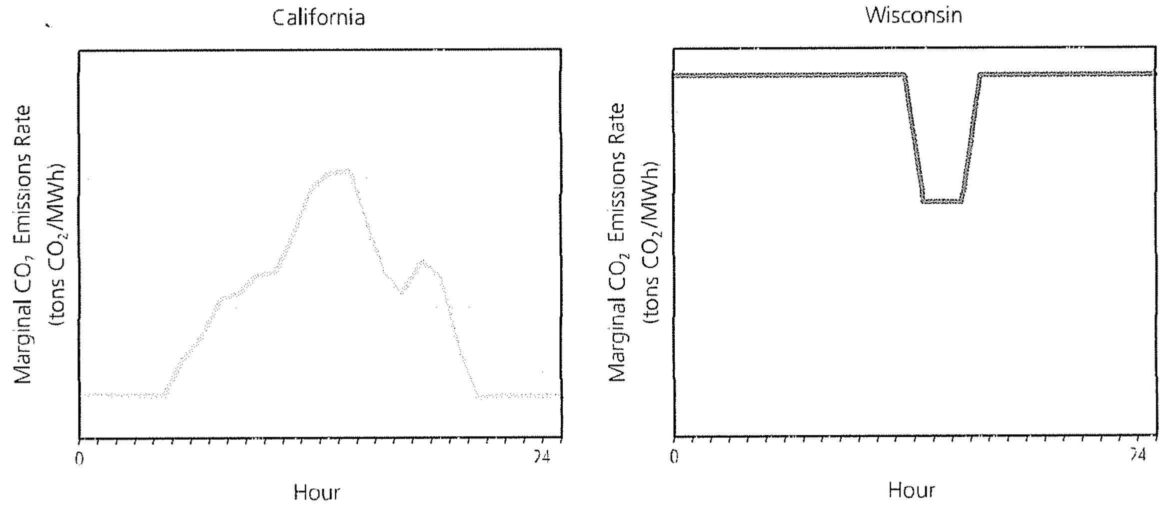
Another factor to consider when determining the cost-effectiveness of an energy efficiency program is how to value the program's effect on GHG emissions. The first step is to determine the quantity of avoided CO_2 emissions from the efficiency program. Once that quantity has been determined, its economic value can be calculated and added to the net benefits of the energy efficiency measures used to achieve the reductions. Currently, some jurisdictions use an explicit monetary CO_2 value in cost-benefit calculations, and some do not. California includes a forecast of GHG values in the avoided costs used to perform the cost-effectiveness tests and Oregon requires that future GHG compliance costs be explicitly considered in utility resource planning. Several utilities, including Idaho Power, PacifiCorp, and Public Service Company of Colorado, include GHG emissions and costs when evaluating supply- and demand-side options, including energy efficiency, in their IRP process.

The GHG emissions emitted through the end use of natural gas and heating oil are driven by the carbon content of the fuel and do not vary significantly by region or time of use. The GHG profiles of electricity generation do differ greatly by technology, fuel mix, and region. A very rough estimate of GHG emissions savings from energy efficiency can be obtained by multiplying the kWh saved by an average emission factor. Alternatively, it can be estimated based upon a weighted average of the heat rates and emission factors for the different types of generators in a utility's generation mix. Such "back of the envelope" methods are useful for agency staff and others who wish to quickly check that results from more sophisticated methods are approximately accurate.

A formal cost-effectiveness evaluation uses marginal emission rates that more accurately reflect the change in emissions due to energy efficiency and have an hourly profile that varies by region. For states in which natural gas is both a base load and peaking fuel, marginal emissions will be higher during peak hours because of the lower thermal efficiency of peaking plants, and therefore energy efficiency measures that focus their kWh savings on-peak will have the highest avoided GHG emissions per kWh saved. However, in states in which coal is the dominant fuel, off-peak marginal emission rates may actually be higher than on-peak if the off-peak generation is coal and on-peak generation is natural gas. Figure 4-2 illustrates this difference, comparing reported marginal emission rates for California and Wisconsin.

To date, monetary values for GHG emissions have been drawn primarily from studies and journal articles and applied in regulatory programs. While there is widespread agreement that GHG reduction policies are likely to impose some cost on CO_2 emissions, achieving consensus on a specific $/ton price for the electricity sector is challenging. As Congress and individual states consider specific GHG legislation, a number of the policy considerations that will affect the CO_2 price remain in flux.

Figure 4-2. Comparison of Marginal CO_2 Emission Rates for a Summer Day in California and Wisconsin



Source: Erickson et al. (2004).

Note: The on-peak marginal emissions rate of each state is set by natural gas peaking units. The off-peak rates are quite different, reflecting the dominance of coal base load generation in Wisconsin and natural gas combined cycle in California.

4.12 Renewable Portfolio Standards

An emerging topic in energy efficiency cost-effectiveness is how to treat the interdependence between energy efficiency and RPS. RPS goals are typically established state by state as a percentage of retail loads in a future target year (e.g., 20 percent renewable energy purchases by 2020). Unlike supply-side investments, energy efficiency, by reducing load, can reduce the amount of renewable energy that must be procured pursuant to RPS targets, thereby reducing RPS compliance cost.

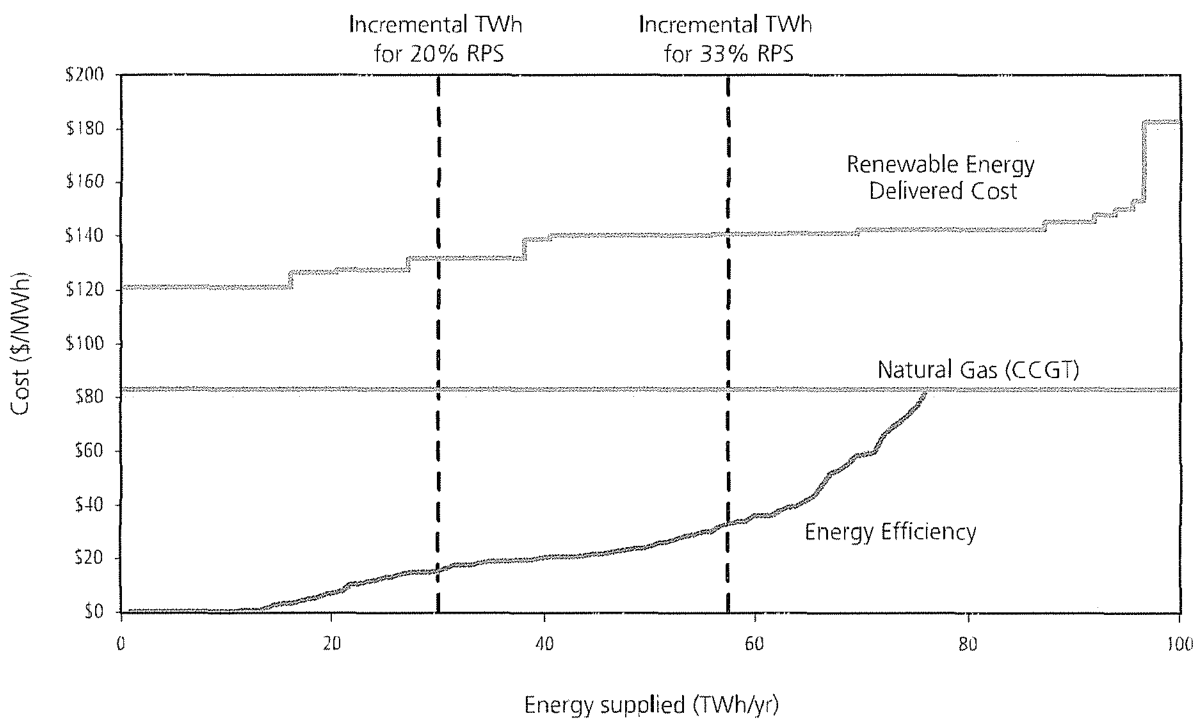
Some renewable technologies can provide energy at costs close to that of conventional generation. However, for many states, the marginal cost of complying with state RPS goals will be set either by more expensive technologies or by distant resources with significant transmission costs. When the cost of renewable energy needed to meet RPS goals is significantly higher than the avoided cost for conventional generation, energy efficiency provides additional savings by reducing RPS compliance costs.

The additional RPS-related savings from energy efficiency for California are illustrated in Figure 4-3. In California, as in many regions, the least-cost conventional base-load resource is combined cycle gas turbine (CCGT), shown here with a cost of $82/MWh. The avoided costs against which energy efficiency has historically been evaluated are based on such conventional generation. This has limited the promotion of energy efficiency to technologies with costs below $80/MWh. In practice, given limited budgets and staff, utilities have focused primarily on technologies with costs of $40/MWh or below.

In comparison, the estimated cost of renewable energy needed to meet California's 20 percent RPS standard is over $130/MWh. So for every 1,000 MWh saved by energy efficiency, the utilities avoid the purchase 800 MWh of conventional generation at $82/MWh and 200 MWh of renewable generation at $130/MWh. Thus the RPS standard increases the cost of avoided energy purchases from $82/MWh to $92/MWh ($82/MWh + [130/MWh - $82/MWh] × 20%).

Utilities in California have begun to incorporate the higher cost of renewable generation in their internal evaluation of load reduction strategies. However, as in most jurisdictions, the cost of meeting RPS targets has not yet been formally included in the adopted avoided cost forecasts against which energy efficiency programs are officially evaluated.

Figure 4-3. Natural Gas, Energy Efficiency, and Renewable Supply Curves for California



Source: Mahone et al. (2008).

4.13 Defining Incremental Cost

In order to apply the avoided cost approach in evaluating benefits of energy efficiency cost-effectiveness, the analyst must also determine the incremental cost of the measures. Energy efficiency portfolio costs are easier to evaluate than benefits, since they are directly observable and auditable. For example, marketing costs, measurement and evaluation costs, incentive costs, and administration costs all have established budgets. The exception to this is in *estimating the incremental measure cost. This is a necessary input for the TRC, SCT, and PCT calculations.*

For each of these tests, the appropriate cost to use is the cost of the energy efficiency device in excess of what the customer would otherwise have made. Therefore, the incremental measure costs must be evaluated with respect to a baseline. For example, a program that provides an incentive to a customer to upgrade to a high-efficiency refrigerator would use the premium of that refrigerator over the base model that would otherwise have been purchased.

Establishing the appropriate baseline depends on the type of measure. In cases where the customer would not have otherwise made a purchase, for example the early replacement of a working refrigerator, the appropriate baseline is zero expenditure.[10] In this case, the incremental cost is the full cost of the new high-efficiency unit. The four basic measure decision types are described in Table 4-4 along with different names often used for each decision type.

Table 4-4. Defining Customer Decision Types Targeted by Energy Efficiency Measures

Decision Type	Definition	Example
New New construction Lost opportunity	Encourages builders and developers to install energy efficiency measures that go above and beyond building standards at the time of construction	Utility offers certification or award to builder of new homes that meet or exceed targets for the efficient use of energy.
Replacement Failure replacement Natural replacement Replace on burnout	Customer is in the market for a new appliance because their existing appliance has worn out or otherwise needs replacing. Measure encourages customer to purchase and install efficient instead of standard appliance.	The utility provides a rebate that encourages the customer to purchase a more expensive, but more efficient and longer-lasting CFL bulb instead of an incandescent bulb.
Retrofit Early replacement	Customer's existing appliance is working with several years of useful life remaining. Measure encourages customer to replace and dispose of old appliance with a new, more efficient one.	The utility provides a rebate toward the purchase of a new, more efficient refrigerator upon the removal of an older, but still working refrigerator.
Retire	Customer is encouraged to remove, but not replace existing fixture.	The utility pays for the removal and disposal of older but still working "second" refrigerators (e.g., in the garage) that customer can conveniently do without.

Table 4-5 summarizes the calculation of measure costs for each of the decision types described above. In the table, "efficient device" refers to the equipment that replaces an existing, less-efficient piece of equipment. "Standard device" refers to the equipment that would be used in industry standard practice to replace an existing device. "Old device" refers to the existing equipment to be replaced.

Table 4-6. Defining Costs and Impacts of Energy Efficiency Measures

Type of Measure	Measure Cost ($/Unit)	Impact Measurement (kWh/Unit and kW/Unit)
New New construction Lost opportunity	Cost of efficient device **minus** cost of standard device *(Incremental)*	Consumption of standard device **minus** consumption of efficient device
Replacement Failure replacement Natural replacement Replace on burnout	Cost of efficient device **minus** cost of standard device *(Incremental)*	Consumption of standard device **minus** consumption of efficient device
Retrofit Early replacement *(Simple)*	Cost of efficient device **plus** installation costs *(Full)*	Consumption of old device **minus** consumption of efficient device
Retrofit Early replacement *(Advanced)**	Cost of efficient device **minus** cost of standard device **plus** remaining present value	*During remaining life of old device:* Consumption of old device **minus** consumption of efficient device *After remaining life of old device:* Consumption of standard device **minus** consumption of efficient device
Retire	Cost of removing old device	Consumption of old device

* The advanced retrofit case is essentially a combination of the simple retrofit treatment (for the time period during which the existing measure would have otherwise remained in service) and the failure replacement treatment for the years *after* the existing device would have been replaced. "Present Value" indicates that the early replacement costs should be discounted to reflect the time value of money associated with the installation of the efficient device compared to the installation of the standard device that would have occurred at a later date.

4.14 Notes

[1] Installed capacity (ICAP), or unforced capacity (UCAP) in some markets, is an obligation of the electric utility (load serving entity, or LSE) to purchase sufficient capacity to maintain system reliability. The amount of ICAP an LSE must typically procure is equal to its forecasted peak load plus a reserve margin. Therefore, reduction in peak load due to energy efficiency reduces the ICAP obligation.

[2] The ability to store natural gas, and to manage the gas system to serve peak demand periods by varying the pressure, reduces the share of gas costs associated with capacity relative to electricity.

3 See <http://www.nwcouncil.org/energy/powerplan/5/Default.htm>.

4 See <http://www.pacificorp.com/Navigation/Navigation23807.html>.

5 See <http://www.nymex.com/ng_fut_csf.aspx> for current market prices at Henry Hub.

6 See <http://www.nymex.com/cp_produc.aspx> for available basis swap products.

7 The specifications may be developed by the utility or developed through a regulatory process with stakeholder input.

8 Forecasts are available at <res://ieframe.dll/tabswelcome.htm>.
See <http://www.eia.doe.gov/oiaf/aeo/> for the latest edition of the Annual Energy Outlook.

9 See <http://www.ethree.com/CPUC/E3_Avoided_Costs_Final.pdf> for a detailed description of the development of avoided costs in California.

10 A simplifying assumption of zero as the baseline expenditure is often used, even though the equipment may have a limited remaining useful life and need replacement in a few years. Table 4-5 presents a more detailed calculation that can be used for early replacement programs.

5: Guidelines for Policy-Makers

A common misperception is that there is a "best" perspective for evaluating the cost-effectiveness of energy efficiency. On the contrary, no single test is more or less appropriate for a given jurisdiction. A useful analogy for the value of the five cost-effectiveness tests is the way doctors use multiple diagnostics to assess the overall health of a patient: each test reflects different aspects of the patient's health. This chapter describes how individual states use each of the five cost-effectiveness tests and why states might choose to emphasize some tests over others. Four hypothetical situations are presented to illustrate how states may emphasize particular tests in pursuit of specific policy goals.

5.1 Emphasizing Cost-Effectiveness Tests

Nationwide, the most common primary measurement of energy efficiency cost-effectiveness is the TRC, followed closely by the SCT. A positive TRC result indicates that the program will, over its lifetime, produce a net reduction in energy costs in the utility service territory. A positive SCT result indicates that the region (the utility, the state, or the United States) will be better off on the whole. Table 5-1 shows the distribution of primary cost-effectiveness tests used by state.

Table 5-1. Primary Cost-Effectiveness Test Used by Different States

PCT	PACT	RIM	TRC	SCT	Unspecified
	CT, TX, UT	FL	CA, MA, MO, NH, NM,	AZ, ME, MN, VT, WI	AR, CO, DC, DE, GA, HI, IA, ID, IL, IN, KS, KY, MD, MT, NC, ND, NJ, NV, OK, OR, PA, RI, SC, VA, WA, WY

Source: Regulatory Assistance Project (RAP) analysis

Cost-effectiveness overall as analyzed by the TRC and SCT is not necessarily the only important aspect to evaluate when designing an energy efficiency portfolio. Even if benefits outweigh costs, some stakeholders can be net winners and others net losers. Therefore, many states also include one or more of the distributional tests to evaluate cost-effectiveness from individual vantage points. Using the results of the distribution tests, the energy efficiency measures and programs offered, their incentive levels, and other elements in the portfolio design can be balanced to provide a reasonable distribution of costs and benefits among stakeholders. Table 5-2 shows the distribution of cost-effectiveness tests used by states for either the primary or secondary consideration.

Table 5-2. Cost-Effectiveness Tests in Use by Different States as Primary or Secondary Consideration

PCT	PACT	RIM	TRC	SCT
AR, FL, GA, HI, IA, IN, MN, VA	AT, CA, CT, HI, IA, IN, MN, NO, NV, OR, UT, VA, TX	AR, DC, FL, GA, HI, IA, IN, KS, MN, NH, VA	AR, CA, CO, CT, DE, FL, GA, HI, IL, IN, KS, MA, MN, MO, MT, NH, NM, NY, UT, VA	AZ, CO, GA, HI, IA, IN, MW, MN, MT, NV, OR, VA, VT, WI

Source: Regulatory Assistance Project (RAP) analysis.

Using the PCT. The PCT provides two key pieces of information helpful in program design: at the measure level it provides some sense of the potential adoption rate, and it can help in setting the appropriate incentive level so as not to provide too small or too unnecessarily large an incentive. Setting the incentive levels is part art and part science. The goal is to get the most participation with the least cost. There is a balance between the PCT results with the PACT and RIM results. The higher the incentive, the higher the PCT benefit cost ratio and the lower the PACT and RIM benefit-cost ratio.

Using the PACT. The PACT provides an indication of how the energy efficiency program compares with supply-side investments. This is used to balance the incentive levels with the PCT. A poor PACT may also result from a low NTG, if, for example, a large number of customers would make the efficiency investment without the program. A poor PACT might also suggest that large incentives are required to induce sufficient adoption of a particular measure.

> **"You get what you measure"**
>
> When selecting cost-effectiveness tests to use as metrics for portfolio, remember the saying, "you get what you measure." If a single distributional test is used as a primary cost-effectiveness test, the portfolio may not balance benefits and costs between stakeholders. This is particularly true as utility incentive mechanisms are introduced that rely on cost-effectiveness results. Overall the results of all five cost tests provide a more comprehensive picture than any one test alone.

Using the RIM. The RIM as a primary consideration test is not as common as the other two distributional tests. If used, it is typically a secondary consideration test done on a portfolio basis to evaluate relative impacts of the overall energy efficiency program on rates. The results will provide a high-level understanding of the likely pressure on rates attributable to the energy efficiency portfolio. A RIM value below 1.0 can be acceptable if a state chooses to accept the rate effect in exchange for resource and other benefits. Efficiency measures with a RIM value below 1.0 can nevertheless represent the least-cost resource for a utility, depending on the time period and long-term fixed costs included in the avoided costs.

5.1.1 Use of Cost-Effectiveness Tests by State

Table 5-3 shows how states use cost-effectiveness tests. Many states use multiple cost-effectiveness tests to provide a more complete picture of energy efficiency cost-effectiveness. Eighteen states use two or more cost-effectiveness tests for some aspect of efficiency evaluation; four of those require all five tests. For example, Hawaii requires that all five tests be included in the analysis of supply and demand options in utility IRPs. Indiana uses all five tests to screen demand-side management (DSM) programs. Minnesota uses all five tests, but considers the SCT to be the most important. Many other states use two or three tests with different weights assigned to each test, or with separate tests being used for separate parts of the process. Several states have adopted formal and in some cases unique modifications to the standard forms of the tests.

The choice of tests and their applications reveal the priorities of the states and the perspectives of their regulatory commissions—the extent to which energy efficiency is considered a resource or the extent to which rates dominate policy implementation of energy efficiency. Some commissions like having a clear formula, using only one or two tests with threshold values to establish program scope.

The following are several examples of the types of decisions regulatory commissions have made regarding cost-effectiveness tests:

- In Colorado, a 2004 settlement with Xcel Energy required the TRC. A 2007 statute requires the use of a variation of the SCT that includes the utility's avoided costs, the valuation of avoided emissions, and NEBs as determined by the regulatory commission.

- Connecticut uses the PACT to screen individual DSM programs and the TRC to evaluate the total benefit of conservation and load management programs and to determine performance incentives.

- In the District of Columbia, the RIM is used for DSM programs. Those which have a cost-benefit ratio of 0.8 and 1.0 may be evaluated for other benefits, including long-term savings, market transformation, peak savings, and societal benefits.

- Iowa requires utilities to analyze DSM programs using the SCT, RIM, PACT, and PCT. According to statute, if the utility uses a test other than the SCT to determine the cost-effectiveness of energy efficiency programs and plans, it must describe and justify its use of the alternative test.

- In Montana, the SCT and TRC are used for the traditionally regulated utility that prepares IRPs. Neither test is required for the utility that conducts portfolio management, although statute specifies that the RIM should not be used.

- Utah requires that DSM programs meet the TRC and PACT in IRP. For supply and demand resources, the primary test is the PACT, calculated under a variety of scenarios; other tests may also be considered.

- California weighs the results of two of the cost-effectiveness tests, TRC and PACT, in this program screening process. California adopted a "Dual-Test" that uses the PACT to ensure that utilities are not over spending on incentives for programs that pass the TRC. The recently adopted shareholder incentive mechanisms use a weighting of two-thirds of the TRC portfolio net benefits result and one-third of the PACT portfolio net benefits result. An incentive is then paid based on the utility's combined results using this metric if the utility's portfolio of savings meets or exceeds the Commission's established energy savings goals.

Table 5-3. Use of Cost-Effectiveness Tests by States

State	Requires All	Primary Test	TRC	SCT	PCT	PACT	RIM	Other	Non-Specific
AK									•
AL									•
AR			•		•	•	•		
AZ*		SCT		•					
CA		TRC	•			•			
CO			•	•					
CT		PACT	•			•			
DC							•	•	
DE*			•						
FL		RIM	•		•		•		
GA			•	•	•		•		
HI	•		•	•	•	•	•		
IA				•	•	•	•		
ID†			•	•	•	•			
IL			•						
IN	•		•	•	•	•	•		
KS*			•				•		
KY									•
LA									•
MA		TRC	•						
MD*									•
ME		SCT		•					
MI									•
MN	•	SCT	•	•	•	•	•		
MO		TRC	•			•			
MS									•
MT			•	•					
NC									•
ND									•
NE									•
NH		TRC	•				•		
NJ								•	
NM		TRC	•						
NV				•		•		•	
NY		TRC	•						
OH									•
OK									•
OR*				•		•			
PA									•
RI								•	
SC									•
SD									•
UT		PACT	•			•			
VA	•		•	•	•	•	•		
VT		SCT		•					
TN									•
TX		PACT				•			
WA								•	
WI		SCT		•					
WV									•
WY									•

* Proposed or not yet codified in statute/Commission Order

† Allows any or all tests, though the RIM may not be used as primary or limiting cost-effectiveness test

Source: Regulatory Assistance Project (RAP) analysis

5.2 Picking Appropriate Costs, Benefits, and Methodology

With the cost-effectiveness tests determined, it is equally important to pick the appropriate costs, benefits, and methodology to align the energy efficiency portfolio with the overall policy goals and context for energy efficiency. The choices should ultimately reflect the situation of the utility and the state, its history in implementing energy efficiency, and other considerations. To provide some guidance, four hypothetical situations are considered along with several recommendations of possible approaches in each situation. Since the hypothetical situations do not consider any specific state, they should be viewed as a starting point for discussion and not specific policy recommendation for every context.

5.2.1 Situation A: Peak Load Growth and Upcoming Capital Investments

States or regions that are experiencing high peak load growth and associated large capital investments will want to ensure that the energy efficiency portfolio appropriately targets the peak and also provides higher benefits for peak load reduction that can be used to justify higher-cost energy efficiency such as air conditioner incentives or demand response.

One approach is to introduce time-specific avoided costs by hour, or by TOU. In addition, it will be important to initiate system planning studies that integrate supply- and demand-side planning so that the energy efficiency programs have the opportunity to defer or delay the supply-side capital investments. Unless the two processes are linked in some way, the energy efficiency program may be successful in reducing peak loads only to find that the capital projects also built. This could create a situation with too much capacity, and overspending on peak load reductions. In order to coordinate demand- and supply-side planning, it is important to start early. The lead time for large supply-side projects can be five or even 10 years. In addition, it is much easier to defer or eliminate the need for the project before the supply-side project proponents are deeply vested in its outcome.

5.2.2 Situation B: Utility Financial Problems

In a situation with a utility with financial problems, due to low load growth and/or a rate freeze, a different set of energy efficiency policies might be considered. Though the problem probably cannot be fixed with energy efficiency program design, there is no need to make it worse.

There are several approaches to encourage energy efficiency without straining the utility financially. One approach is to introduce decoupling or another automatic rate adjustment for reduced sales from energy efficiency to ensure recovery of fixed costs that have already been allowed in a prior rate case. A rate adjustment, whether tied to decoupling or not, may also help improve the utility financial situation.

If rate adjustments are not possible (whether through direct adjustment, decoupling, or another approach), another option may be to limit the impact of energy efficiency by specifying a minimum portfolio RIM. This will reduce the level of energy that can be saved but allow the portfolio to continue, perhaps with some lower-scoring programs placed on hiatus, while the financial issues of the utility are addressed.

5.2.3 Situation C: Targeting Load Pockets

If a utility has areas of growing load that require new transmission and/or generation investments to be made, energy efficiency may provide an alternative. In this case, it may be less expensive to use energy efficiency and demand response to reduce peak loads than to build new supply-side infrastructure. Using demand-side resources to alleviate a load pocket also has a lower impact on the environment.

In order to target the load pockets, the energy efficiency portfolio should include programs that specifically target peak load reduction in these areas. This can be done by increasing marketing of the same programs used service-territory-wide, or by developing a specific program to target peak load reductions in an area. Area- and time-specific costing should be introduced to estimate the value of the peak load reductions. Energy efficiency program managers should be given the authority to target certain areas. In this case, the equity of providing all of the same measures service-territory-wide may be overshadowed by value of a targeted program.

Targeting marketing and implementation is, by definition, discriminatory, but for legitimate, cost-based reasons. Targeting efficiency for areas with capacity constraints can be a prudent and least-cost means of accommodating load growth or meeting reliability criteria. While they may appear to favor certain customers, targeted efforts can provide sufficient incremental value to offer net benefits for all customers.

As in Situation A, it will be important in Situation B to initiate system planning studies that integrate supply- and demand-side planning so that the energy efficiency programs have the opportunity to defer or delay the supply-side load pocket mitigation measures.

5.2.4 Situation D: Aggressive Greenhouse Gas and RPS Policies

Many states are introducing the RPS and beginning to implement aggressive GHG policies. In these situations, policy-makers will need to emphasize energy savings. One approach to consider is to focus on the TRC or SCT, and not to use the RIM results. Policy-makers might also consider including a forecast of avoided CO_2 reductions in the avoided costs. In addition, including the avoided costs of the renewable energy or low-carbon resource that would otherwise be purchased (nuclear, renewables, carbon-capture, and sequestration) as the marginal resource can increase the avoided costs. This raises the quantity of efficiency measures and programs considered cost-effective. Finally, policy-makers will want to focus the cost-effectiveness tests at the portfolio level, rather than at the program or measure level.

6: Detailed Cost-Effectiveness Test Comparison—How Is Each Cost-Effectiveness Test Used?

This chapter describes the cost-effectiveness tests in order to provide greater understanding of calculation, results, and appropriate use of each test. Information is provided on the perspective, purpose, costs, benefits, and other considerations for each of the cost-effectiveness tests.

6.1 Participant Cost Test

The PCT examines the costs and benefits from the perspective of the customer installing the energy efficiency measure (homeowner, business, etc.). Costs include the incremental costs of purchasing and installing the efficient equipment, above the cost of standard equipment, that are borne by the customer. The benefits include bill savings realized to the customer through reduced energy consumption and the incentives received by the customer, including any applicable tax credits. Table 6-1 outlines the benefits and costs included in the PCT. In some cases the NPV of incremental operations and maintenance costs (or savings) may also be included.

Table 6-1. Benefits and Costs Included in the Participant Cost Test

Benefits and Costs from the Perspective of the Customer Installing the Measure	
Benefits	*Costs*
▪ Incentive payments ▪ Bill savings realized ▪ Applicable tax credits or incentives	▪ Incremental equipment costs ▪ Incremental installation costs

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

The primary use of the PCT is to assess the appeal of an energy efficiency measure to potential participants. The higher the PCT, the stronger the economic incentive to participate. The PCT functions similarly to a simple payback calculation, which determines how many years it takes to recover the costs of purchasing and installing a device through bill savings. A cost-effective measure will have a high PCT (above 1) and a low payback period. The PCT also provides useful information for designing appropriate customer incentive levels. A high incentive level will produce a high PCT benefit-cost ratio, but reduce the PACT and RIM results. This is because incentives given to customers are seen as "costs" to the utility. The PCT, PACT, and RIM register incentive payments in different ways based on their perspective. Utilities must balance the participant payback with the goal of also minimizing costs to the utility and ratepayers.

> A positive PCT (above 1) shows that energy efficiency provides net savings for the customer over the expected useful life of the efficiency measure.

6.1.1 Additional Considerations

As a measure of payback period or economic appeal, the PCT reflects an important aspect of potential participation rates. However, it is not a comprehensive evaluation of all the determinants that influence customer participation. For example, the PCT does not consider the level of marketing and outreach efforts (or expenditures) to promote the program, and marketing can be a major driver of adoption rates. In addition, new technologies may have high upfront costs, or steep learning curves, which yield limited adoption despite high PCT ratios. As a key example, energy-efficient CFLs generally reach a plateau despite high cost-effectiveness, indicating the importance of other factors in behavior besides bill savings.[1] This can be due to several factors including customer resistance and limited availability of premium features, such as the ability to dim.

Ideally the PCT will be performed using the marginal retail rate avoided by the customer. In practice the PCT is often performed using the utility's average rates for an applicable customer class. With tiered and TOU rates, the marginal rate paid by individual customers can vary significantly, which makes the use of marginal rate savings in the PCT somewhat more difficult. Furthermore, the impact of energy efficiency on a customer's peak load is difficult to predict, making changes in customer demand charges hard to estimate. In practice, the level of effort required to estimate the customers' actual savings given their consumption profile and applicable rate schedule is significant. Often utilities find it is not worth the effort at the program design or evaluation level, though it may be useful for individual customer audits. Thus the PCT gives an indication of the direct cost-based incentives for customers to participate in a given energy efficiency program.

6.2 Program Administrator Cost Test

The PACT examines the costs and benefits of the energy efficiency program from the perspective of the entity implementing the program (utility, government agency, nonprofit, or other third party). The costs included in the PACT include overhead and incentive costs. Overhead costs are administration, marketing, research and development, evaluation, and measurement and verification.[2] Incentive costs are payments made to the customers to offset purchase or installations costs (mentioned earlier in the PCT as benefits).[3] The benefits from the utility perspective are the savings derived from not delivering the energy to customers. Depending on the jurisdiction and type of utility, the "avoided costs" can include reduced wholesale electricity or natural gas purchases, generation costs, power plant construction, transmission and distribution facilities, ancillary service and system operating costs, and other components.[4] These elements are discussed in more detail in Chapter 4. The benefits and costs included in the PACT are summarized in Table 6-2.

Table 6-2. Benefits and Costs Included in the Program Administrator Test

Benefits and Costs to the Utility, Government Agency, or Third Party Implementing the Program	
Benefits	**Costs**
▪ Energy-related costs avoided by the utility ▪ Capacity-related costs avoided by the utility, including generation, transmission, and distribution	▪ Program overhead costs ▪ Utility/program administrator incentive costs ▪ Utility/program administrator installation costs

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects

The PACT allows utilities to evaluate costs and benefits of energy efficiency programs (and/or demand response and distributed generation) on a comparable basis with supply-side investments. A positive PACT indicates that energy efficiency programs are lower-cost approaches to meeting load growth than wholesale energy purchases and new generation resources (including delivery and system costs). States with large needs for new supply resources may emphasize the PACT to build efficiency alternatives into procurement planning.[5]

> A positive PACT indicates that the total costs to save energy are less than the costs of the utility delivering the same power. A positive PACT also shows that customer average bills will eventually go down if efficiency is implemented.

6.2.1 Additional Considerations

The PACT provides an estimate of energy efficiency costs as a utility resource. Even the most comprehensive avoided cost estimates cannot capture all of the attributes of energy valued by the utility. In addition, the PACT only includes the program administrator costs and not those costs borne by customers. Therefore the PACT may not be seen as sufficiently comprehensive as a primary determinant of cost-effectiveness.

As with all of the cost-effectiveness tests, there are simplifications made in the calculation that should be understood when they are applied. For example, the PACT does not incorporate the different regulatory and financial treatment of utility investments in energy efficiency versus utility infrastructure. Therefore, while the PACT provides an estimate of energy efficiency as a resource, a positive PACT result does not imply that a utility will be better off financially. Finally, in order to get meaningful results on the PACT, care must be taken to estimate the actual resource savings to the utility from the energy efficiency program, including the timing and certainty of load reductions and the resulting impact on the utility supply costs.

Since the PACT includes the full savings to the utility but not the full costs of purchasing and installing the energy efficiency measures (which are paid by participants), the PACT is usually the easiest cost-effectiveness test to pass. In the SCE program featured in Appendix C, for example, the PACT ratio is 9.9—a higher value than that produced by any other cost-effectiveness test.

> Jurisdictions seeking to increase efficiency implementation may choose to emphasize the PACT, which compares energy efficiency as a utility investment on par with other resources. Because the PACT includes only utility costs (and not customer contributions), the PACT is often the most permissive (and most positive) cost-effectiveness test.

6.3 Ratepayer Impact Measure

The RIM examines the impact of energy efficiency programs on utility rates. Unlike typical supply-side investments, energy efficiency programs reduce energy sales. Reduced energy sales can lower revenues and put upward pressure on retail rates as the remaining fixed costs are spread over fewer kWh. The costs included in the RIM are program overhead and incentive payments and the cost of lost revenues due to reduced sales.[6] The benefits included in the RIM are the avoided costs of energy saved through the efficiency measure (same as the PACT). Table 6-3 *outlines the benefits and costs included in the* RIM.

Table 6-3. Benefits and Costs Included in the Rate Impact Measure Test

Benefits and Costs to Ratepayers Overall; Would Rates Need to Increase?	
Benefits	**Costs**
• Energy-related costs avoided by the utility • Capacity-related costs avoided by the utility, including generation, transmission, and distribution	• Program overhead costs • Utility/program administrator incentive costs • Utility/program administrator installation costs • Lost revenue due to reduced energy bills

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

Note The PACT and the RIM use the same benefits

The RIM also gives an indication of the distributional impacts of efficiency programs on non-participants. Participants may see net benefits (by lowering their bills through reduced energy consumption) while non-participating customers may experience rate increases due to the same programs. As the impacts on non-participating customers depend on many factors including the timing of adjustments to rates, the RIM is only an approximation of these impacts.

> The RIM answers the question, "All other things being equal, what is the impact of the energy efficiency program on utility rates if they were to be adjusted to account for the program?" A negative RIM implies that rates would need to increase for the utility to achieve the same level of earnings in the short term.[7]

In the vast majority of cases, the RIM is negative since the retail rate is typically higher than the utility's avoided cost. The RIM may be negative, even at the same time as average bills decrease (as evaluated using the PACT). Therefore, policy-makers have to decide whether to emphasize customer bills by using the PACT or customer rates by using the RIM.[8] The main reason cited for use of the RIM is to protect customer classes. Chapter 2 of the National Action Plan for Energy Efficiency Report (National Action Plan for Energy Efficiency, 2006) suggests effective ways to protect customer groups from rate increases in the rate design process that do not limit the use of energy efficiency. As described in Section 5.1 above, most jurisdictions do not choose the RIM as a primary test; many use it as a secondary consideration, if at all.[9]

6.3.1 Additional Considerations

It is sometimes observed that even least-cost utility investments made to maintain reliability often lead to a rate increase, yet the RIM has not been applied to these initiatives. One key consideration in assessing the RIM is that there is typically an allocation of fixed costs in the variable $/kWh rate. The fixed costs included in rates reflect the utility's existing revenue requirement and do not necessarily reflect future capital costs avoided through energy efficiency. Customers are often resistant to high fixed charges and lumpy utility investments are not always considered avoidable through efficiency savings that are realized gradually over time. In addition, avoided costs are often based on market prices, which tend to emphasize variable and short-term as opposed to long-term costs. Because many utilities have multiple standard, tiered, and TOU rate options, the actual marginal revenue loses to the utility can be difficult to estimate and not accurately captured when customer class average rates are used in the RIM calculation. Other considerations in the RIM, including the relationship to utility financial health over time and capacity-focused programs that yield higher RIM results, are discussed in further detail in Section 3.2.2 above.

> The RIM is the most restrictive of the five cost-effectiveness tests. When the utility's retail rates are higher than its avoided costs, the RIM will almost always be negative. Thus policy-makers may choose to emphasize the PACT and use the RIM as a secondary consideration for balancing the distribution of rate impacts.

6.4 Total Resource Cost Test

The TRC measures the net benefits of the energy efficiency program for the region as a whole. Costs included in the TRC are costs to purchase and install the energy efficiency measure and overhead costs of running the energy efficiency program. The benefits included are the avoided costs of energy (as with the PACT and the RIM). Table 6-4 outlines the benefits and costs in the TRC.

Table 6-4. Benefits and Costs Included in the Total Resource Cost Test

Benefits and Costs from the Perspective of All Utility Customers (Participants and Non-Participants) in the Utility Service Territory	
Benefits	**Costs**
▪ Energy-related costs avoided by the utility ▪ Capacity-related costs avoided by the utility, including generation, transmission, and distribution ▪ Additional resource savings (e.g., gas and water if utility is electric) ▪ Monetized environmental and non-energy benefits (see Section 4.9) ▪ Applicable tax credits (see text)	▪ Program overhead costs ▪ Program installation costs ▪ Incremental measure costs (whether paid by the customer or the utility)

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects

The primary purpose of the TRC is to evaluate the net benefits of energy efficiency measures to the region as a whole. Unlike the tests describe above, the TRC does not take the view of individual stakeholders. It does not include bill savings and incentive payments, as they yield an intra-regional transfer of zero ("benefits" to customers and "costs" to the utility that cancel each other on a regional level). For some utilities, the region considered may be limited strictly to its own service territory, ignoring benefits (and costs) to neighboring areas (a distribution-only utility may, for example, consider only the impacts to its distribution system). In other cases, the region is defined as the state as a whole, allowing the TRC to include benefits to other stakeholders (e.g., other utilities, water utilities, local communities). The TRC is useful for jurisdictions wishing to value energy efficiency as a resource not just for the utility, but for the entire region. Thus the TRC is often the primary test considered by those states seeking to include the benefits not just to the utility and its ratepayers, but to other constituents as well. The TRC may be considered the sum of the PCT and RIM, that is, the participant and non-participant cost-effectiveness tests. The TRC is also useful when energy efficiency might fall through the cracks taken from the perspective of individual stakeholders, but would yield benefits on a wider regional level.[10]

The inclusion of tax credits or incentives depends to some extent on the region considered. A municipal utility might consider state and federal tax incentives as a benefit from outside the region defined for the TRC. For a utility with a service territory that includes all or most of a particular state, state tax incentives would be an intra-regional transfer that is not included in the TRC. Some jurisdictions chose to consider all tax incentives as transfers excluded from the TRC. Generally speaking, tax incentives in the TRC should be treated consistently with the other resources to which energy efficiency may be compared.

> The TRC shows the net benefits of the energy efficiency program as a whole. It can be used to evaluate energy efficiency alongside other regional resources and communicate with other planning agencies and constituencies.

6.4.1 Additional Considerations

The TRC is similar to the PACT except that it considers the cost of the measure itself rather than the incentive paid by the utility. Because the incentives are less than the cost of the measure in most cases, the TRC is usually lower than the PACT. Therefore, the TRC will be a more restrictive test than the PACT and fewer measures will pass the TRC. Indeed, it is not unusual for a measure to fail the TRC while appearing economical both to the utility (PACT) and to the participant (PCT). Due to the incentives paid by the utility, the participant and the utility each pay only a portion of the full incremental cost of the measure, which is the cost to the region as a whole considered by the TRC.

The TRC says nothing about the distributional impacts of the costs of energy efficiency. To address distributional effects, many jurisdictions that use the TRC as the primary criteria also look at other cost-effectiveness tests. In situations where budgets constrain the amount of energy efficiency investment, a threshold value may be used. A lower threshold may be applied to programs that serve low-income or hard-to-reach groups, representing the distinct societal value of reaching these customer groups that is not reflected in the benefit-cost calculation.

> The TRC is more restrictive than the PACT because it includes the full cost of the energy efficiency measure and not just the incentives paid by the utility. As a result, a program may have a positive PACT and PCT but still not pass the TRC, because the utility and customer pay a fraction of the total measure cost that is included in the TRC.

6.5 Societal Cost Test

The SCT includes all of the costs and benefits of the TRC, but it also includes environmental and other non-energy benefits that are not currently valued by the market. The SCT may also include non-energy costs, such as reduced customer comfort levels. Table 6-5 outlines the benefits and costs in the SCT.

Table 6-5. Benefits and Costs Included in the Societal Cost Test

Benefits and Costs to All in the Service Territory, State, or Nation as a Whole	
Benefits	**Costs**
▪ Energy-related costs avoided by the utility ▪ Capacity-related costs avoided by the utility, including generation, transmission, and distribution ▪ Additional resource savings (e.g., gas and water if utility is electric) ▪ Non-monetized benefits (and costs) such as cleaner air or health impacts	▪ Program overhead costs ▪ Program installation costs ▪ Incremental measure costs (whether paid by the customer or the utility)

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

In some cases, emissions costs are included in the market price used to determine avoided costs or are otherwise explicitly included in the TRC calculation (as in the SCE program example[11]). Emissions permit costs may already be included in the market price of electricity in some jurisdictions. In other jurisdictions, emissions are included in the SCT.[12]

As with the TRC, the inclusion of tax incentives varies by jurisdiction. Those using a broad definition of the society exclude tax incentives as a transfer. Others will include tax incentives originating from outside the immediate region considered.

> The SCT includes costs and benefits beyond the immediate region and those that are not monetized in the TRC, such as environmental benefits or GHG reductions.

6.5.1 Additional Considerations

Increasingly, benefits historically included only in the SCT are being included in the TRC in some jurisdictions. Including a cost for carbon dioxide (CO_2) emissions is a prime example. Though the future cost associated with CO_2 emissions remains highly uncertain and difficult to quantify, many utilities believe it is increasingly unlikely that the cost will be zero. In California, an approximate forecast is developed through a survey of available studies and literature. The IRPs of many utilities now include a risk or portfolio analysis to calculate an "expected" carbon value or to determine if the additional cost of a flexible portfolio is sufficiently robust under a range of possible futures.

Water savings are also being explicitly included in the TRC instead of the SCT. This helps promote measures such as front-loading clothes washers, which provide water savings that are of value to the region but beyond the direct purview of electric and natural gas utilities. There is also increasing interest in the West, where water supply is particularly energy intensive, in targeting the energy savings possible through water conservation.[13]

Some commissions eschew the SCT because factors not included in the TRC are found to be beyond their jurisdiction. Where this is the case, legislation would be needed to create or clarify the opportunity for commissions to consider the SCT. On the other hand, some states require that the societal test be considered when commissions evaluate energy efficiency programs. Some states adopt the California methodology, while other states adopt modified versions, adding or deleting costs or benefits consistent with state priorities. For example, Illinois uses a modified TRC defined in statute, in which gas savings are not included in electricity program evaluation. The New York State Energy Research and Development Authority (NYSERDA) calculates the TRC for three scenarios, adding non-energy benefits in Scenario 2 and macroeconomic benefits in Scenario 3.

> Energy efficiency is among the most cost-effective ways to reduce carbon emissions. The SCT is a useful test for jurisdictions seeking to implement or comply with GHG reduction goals. It can also be used to evaluate water savings.

6.6 Notes

[1] The PCT is only one of the determinants of customer participation, and bill savings are not the sole factor in a customer's decision to implement energy efficiency. Marketing and customer decision-making studies can be used to better understand the levels of customer participation more directly. See Golove and Eto, 1996; Schleich and Gruber, 2008.

[2] At a minimum, overhead costs generally include the salary (and benefits) of those employees directly involved in promoting energy efficiency. Some jurisdictions opt to include an allocation of fixed costs (i.e., office space) while others do not. To the extent they are applicable, research and development, marketing, evaluation, measurement, and verification and other costs may be included in the overall total, or reported individually as they are for the SCE example shown here. In cases where energy efficiency program costs are subject to special treatment (e.g., public funding and shareholder incentive mechanisms), detailed definitions of what may be included as an overhead cost are often required.

[3] The simplest example is a rebate paid to the customer for the purchase of an efficient appliance. However, as programs have grown in scope and complexity, so has the definition of an incentive. Two additional types of incentive are common: direct install costs and upstream payments. In many cases, the utility performs or pays for the labor and installation associated with an efficiency measure. Such payments, which are not for the equipment itself, but nevertheless reduce the cost to the customer, are considered direct install costs. Another approach, which is now common for CFL programs, calls for utilities to pay incentives directly to manufacturers and distributors. These upstream payments lower the retail cost of the product, though no rebate is paid directly to the customer.

[4] Avoided cost benefits vary according to the time and location of the energy savings. Chapter 5 describes various alternative approaches for estimating the benefits of energy efficiency.

[5] A specialized application of the PACT is in local IRPs. When a local area is at or near the system's capacity to serve its load, significant infrastructure investments are often required. If such investments can be deferred by reducing loads or load growth, there is additional value to the utility in installing energy efficiency and other distributed resources in that area. The additional savings that can be realized by the utility can justify increased customer incentives and marketing for a targeted efficiency program.

[6] The RIM, PACT, and PCT assess the impacts of the program from different, but interconnected stakeholder perspectives. The RIM includes the overhead and incentive payments included as costs in the PACT, but also includes revenue losses. The RIM recognizes the incentives and bill savings reported as benefits in the PCT, but the RIM reports these terms as costs (revenues losses).

[7] Even with a negative RIM result, efficiency may still be the most cost-effective means of meeting load growth. The full array of long-term investment options considered in utility resource planning cannot always be captured in the avoided costs used to evaluate energy efficiency.

[8] The exception to the predominance of the negative RIM result are utilities that can serve most of their loads with existing, low-cost generation, but are facing high costs to build new generation. In such cases, the avoided costs for energy efficiency may well be higher that the utility's retail rates.

[9] In practice, since utility rates are often frozen between rate-setting cycles and not continuously reset, the utility itself absorbs the losses (or gains) in its earnings until rates are adjusted. These adjustments can be made in several ways: the regular rate-setting cycle, a decoupling mechanism, or a revenue adjustment mechanism. In the long run, the reduced capital investments necessary as a result of energy efficiency will mitigate the rate increases. The National Action Plan for Energy Efficiency's Energy Efficiency Benefits Calculator can evaluate these impacts over time: <http://www.epa.gov/cleanenergy/energy-programs/napee/resources/calculator.html>. This is discussed in more detail in Chapter 4.

[10] As an example, in areas of competitive procurement, distribution-only utilities may not see energy efficiency as an immediate interest because it may not yield significant T&D savings (and generation costs are not part of their purview). In such a case, the utility may not implement energy efficiency even if it is cost-effective from a regional perspective. As a result, regulators may ask the utility to focus on the TRC rather than the PACT when evaluating efficiency programs.

[11] California includes emissions permits and trading costs in the avoided cost calculations of the TRC.

[12] Tax incentives paid by the state or federal governments and financing costs are excluded from the SCT, because they are considered a zero net transfer. A wide range of NEBs have been considered and evaluated throughout the United States. For the participant and community, these NEBs resulted in increased comfort, improved air quality, greater convenience, and improved health and aesthetic benefits. For the utility, fewer shut-off notices or bill complaints occurred.

[13] The California Public Utilities Commission has approved pilot programs for investor-owned utilities to partner with water agencies and provide funding for water conservation incentives that provide energy savings (A.07-01-024).

Appendix A: National Action Plan for Energy Efficiency Leadership Group

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Facilitators

U.S. Department of Energy

U.S. Environmental Protection *Agency*

Appendix B: Glossary

Avoided costs: The forecasted economic benefits of energy savings. These are the costs that would have been spent if the energy efficiency had not been put in place.

Discount rate: A measure of the time value of money. The choice of discount rate can have a large impact on the cost-effectiveness results for energy efficiency. As each cost-effectiveness test compares the net present value of costs and benefits for a given stakeholder perspective, its computation requires a discount rate assumption.

Energy efficiency: The use of less energy to provide the same or an improved level of service to the energy consumer in an economically efficient way. "Energy conservation" is a term that has also been used, but it has the connotation of doing without in order to save energy rather than using less energy to perform the same or better function.

Evaluation, measurement, and verification: The process of determining and documenting the results, benefits, and lessons learned from an energy efficiency program. The term "evaluation" refers to any real time and/or retrospective assessment of the performance and implementation of a program. "Measurement and verification" is a subset of evaluation that includes activities undertaken in the calculation of energy and demand savings from individual sites or projects.

Free rider: A program participant who would have implemented the program measure or practice in the absence of the program.

Impact evaluation: Used to determine the actual savings achieved by different programs and specific measures.

Integrated resource planning: A public planning process and framework within which the costs and benefits of both demand- and supply-side resources are evaluated to develop the least-total-cost mix of utility resource options. In many states, integrated resource planning includes a means for considering environmental damages caused by electricity supply/transmission and identifying cost-effective energy efficiency and renewable energy alternatives.

Levelized cost: A constant value or payment that, if applied in each year of the analysis, would result in a net present value equivalent to the actual values or payments which change (usually increase) each year. Often used to represent, on a consistent basis, the cost of energy saved by various efficiency measures with different useful lives.

Marginal cost: The sum that has to be paid for the next increment of product or service. The marginal cost of electricity is the price to be paid for kilowatt-hours above and beyond those supplied by presently available generating capacity.

Marginal emission rates: The emissions associated with the marginal generating unit in each hour of the day.

Market effects evaluation: Used to estimate a program's influence on encouraging future energy efficiency projects because of changes in the energy marketplace. All categories of programs can have market effects evaluations; however, these evaluations are primarily associated with market transformation programs that indirectly achieve impacts.

Market transformation: A reduction in market barriers resulting from a market intervention, as evidenced by a set of market effects, that lasts after the intervention has been withdrawn, reduced, or changed.

Measures: Installation of equipment, installation of subsystems or systems, or modification of equipment, subsystems, systems, or operations on the customer side of the meter, in order to improve energy efficiency.

Net-to-gross ratio: A key requirement for program-level evaluation, measurement, and verification. This ratio accounts for only those energy efficiency gains that are attributed to, and the direct result of, the energy efficiency program in question. It gives evaluators an estimate of savings that would have occurred even without program incentives.

Net present value: The value of a stream of cash flows converted to a single sum in a specific year, usually the first year of the analysis. It can also be thought of as the equivalent worth of all cash flows relative to a base point called the present.

Nominal: For dollars, "nominal" means the figure representing the actual number of dollars exchanged in each year, without accounting for the effect of inflation on the value or purchasing power. For interest or discount rates, "nominal" means that the rate includes the rate of inflation (real rate plus inflation rate equals the nominal rate).

Participant cost test: A cost-effectiveness test that measures the economic impact to the participating customer of adopting an energy efficiency measure.

Planning study: A study of energy efficiency potential used by demand-side planners within utilities to incorporate efficiency into an integrated resource planning process. The objective of a planning study is to identify energy efficiency opportunities that are cost-effective alternatives to supply-side resources in generation, transmission, or distribution.

Portfolio: Either (a) a collection of similar programs addressing the same market, technology, or mechanisms or (b) the set of all programs conducted by one organization.

Potential study: A study conducted to assess market baselines and energy efficiency savings potentials for different technologies and customer markets. Potential is typically defined in terms of technical, economic, achievable, and program potential.

Program administrators: Typically procure various types of energy efficiency services from contractors (e.g., consultants, vendors, engineering firms, architects, academic institutions, community-based organizations), as part of managing, implementing, and evaluating their portfolio of energy efficiency programs. Program administrators in many states are the utilities; in some states they are state energy agencies or third parties.

Program design potential study: Can be undertaken by a utility or third party for the purpose of developing specific measures for the energy efficiency portfolio.

Ratepayer impact measure: A cost-effectiveness test that measures the impact on utility operating margin and whether rates would have to increase to maintain the current levels of margin if a customer installed energy efficient measures.

Real: For dollars, "real" means that the dollars are expressed in a specific base year in order to provide a consistent means of comparison after accounting for inflation. For interest and discount rates, "real" means the inflation rate is not included (the nominal rate minus the inflation rate equals the real rate).

Societal cost test: A cost-effectiveness test that measures the net economic benefit to the utility service territory, state, or region, as measured by the total resource cost test, plus indirect benefits such as environmental benefits.

Time-of-use periods: Blocks of time defined by the relative cost of electricity during each block. Time-of-use periods are usually divided into three or four time blocks per 24-hour period (on-peak, mid-peak, off-peak, and sometimes super off-peak) and by seasons of the year (summer and winter).

Total resource cost test: A cost-effectiveness test that measures the net direct economic impact to the utility service territory, state, or region.

Utility/program administrator cost test: The program administrator cost test, also known as the utility cost test, is a cost-effectiveness test that measures the change in the amount the utility must collect from the customers every year to meet an earnings target—e.g., a change in revenue requirement. In a number of states, this test is referred to as the program administrator cost test. In those cases, the definition of the "utility" is expanded to program administrators (utility or third party).

Appendix C: Cost-Effectiveness Tables of Best Practice Programs

Southern California Edison Residential Incentive Program

SCE's Residential Energy Efficiency Incentive Program provides customer incentives for efficient lighting and appliances (not including HVAC). It is part of a coordinated statewide mass market efficiency program that coordinates marketing and outreach efforts. This program is used as the example in Section 3.1 to illustrate the calculation of each of the cost-effectiveness tests.

The values shown in Tables C-1, C-2 and C-3 are for the fourth quarter of 2006. Note that dollar benefits associated with emissions reductions are included in the forecasted avoided cost of energy, and are therefore not separately reported. The other category in this case includes direct implementation activity costs incurred by SCE that are over and above the cost of the efficiency measure. Direct installation costs paid by the utility that offset the cost of the measure are included under "program incentives."

Table C-1. SCE Program Costs

Cost Inputs			Var.
Program overhead			
Program administration	$	898,548	
Marketing and outreach	$	559,503	
Rebate processing	$	1,044,539	
Research and development		—	
Evaluation, measurement, and verification		—	
Shareholder *incentive*		—	
Other	$	992,029	
Total program administration	$	3,494,619	O
Program incentives			
Rebates and incentives	$	1,269,393	
Direct installation costs	$	564,027	
Upstream payments	$	13,624,460	
Total incentives	$	15,457,880	I
Total program costs	$	18,952,499	
Net measure equipment and installation	$	41,102,993	M

Source: SCE 4TH Quarter 2006 EE Report & Program Calculators, <http://www.sce.com/AboutSCE/Regulatory/eefilings/Quarterly.htm>

Table C-2. SCE Program Benefits

Net Benefit Inputs				Var.
Resource savings	Units		$	
Energy (MWh)	2,795,290	$	187,904,906	
Peak demand (kW)	55,067		—	
Total electric	—	$	187,904,906	
Natural gas (MMBtu)	—		—	
Total resource savings		$	187,904,906	S
Participant bill savings	Electric	$	278,187,587	B
	Gas		—	
Monetized emission savings	Tons			
NO_x	421,633		—	
SO_x	—		—	
PM_{10}	203,065		—	
CO_2	1,576,374		—	
Total emissions		$	—	E
Non-monetized emissions (externalities)	Tons			
NO_x	—		—	
SO_x	—		—	
PM_{10}	—		—	
CO_2	—		—	
Total emissions			—	EXT
Non-energy benefits		$	—	NEB

Source: SCE 4TH Quarter 2006 EE Report & Program Calculators, <http://www.sce.com/AboutSCE/Regulatory/eefilings/Quarterly.htm>

Table C-3. SCE Program Cost-Effectiveness Test Results

Summary of Cost-Effectiveness Results

Lifecycle costs and benefits

Test	Cost	Benefits	Ratio
PCT	$ 41,102,993	$ 293,645,467	7.14
PAC	$ 18,952,499	$ 187,904,906	9.91
RIM	$ 297,140,086	$ 187,904,906	0.63
TRC	$ 44,597,612	$ 187,904,906	4.21
SCT	$ 44,597,612	$ 187,904,906	4.21

Costs and benefits included in each test

PCT	= M	= B + I
PAC	= O + I	= S
RIM	= O + I + B	= S
TRC	= O + M	= S + E
SCT	= O + M	= S + E + EXT + NEB

Estimated levelized costs and benefits

Test	Cost $/kWh	Benefits $/kWh
PCT	$0.026	$0.184
PAC	$0.012	$0.117
RIM	$0.186	$0.117
TRC	$0.028	$0.117
SCT	$0.028	$0.117

Assumptions for levelized calculations

Average measure life	14
WACC	8.50%
Discount factor for savings	57%

Source: SCE 4TH Quarter 2006 EE Report & Program Calculators, <http://www.sce.com/AboutSCE/Regulatory/eefilings/Quarterly.htm>

Note: The discount factor uses an estimate of average measure life and the utility weighted average cost of capital to convert the net present value of costs and benefits into levelized annual figures. The levelized annual costs and benefits are then used to calculate costs and benefits on a $/kWh basis

Avista Regular Income Programs

Avista is an electric and natural gas utility in the Northwest with headquarters in Spokane, Washington. The best practice program highlighted here represents the 2007 Regular Income Portfolio of electricity energy efficiency measures implemented by Avista. The numbers were obtained from the Triple-E Report produced by the Avista Demand-Side Management Team (Table 13E).

Avista reports gross results, which do not take free riders into account. Installation rates, persistence/failure and rebound ("snap-back" or "take-back") are taken into account in Avista's estimates of energy savings. Avista does consider NEBs when they are quantifiable and defensible, which are predominately benefits from the customer's perspective.

Avista contributed to projects saving over 53 million kWh and 1.5 million therms in 2007. The HVAC and lighting categories made up 81 percent of the electric savings while 97 percent of the natural gas savings were in the HVAC and Shell categories.

Avista incorporates quantifiable labor and operation and maintenance as non-energy benefits, which are included in the PCT, SCT, and TRC cost-effectiveness tests.

Table C-4. Avista Program Costs

Cost Inputs			Var.
Program overhead			
Program administration	$	2,564,894	
Marketing and outreach		—	
Rebate processing		—	
Research and development		—	
Evaluation, measurement, and verification		—	
Shareholder incentive		—	
Other		—	
Total program administration	$	2,564,894	O
Program incentives			
Rebates and incentives	$	4,721,881	
Direct installation costs		—	
Upstream payments		—	
Total incentives	$	4,721,881	I
Total program costs	$	7,286,775	
Net measure equipment and installation	$	16,478,257	M

Source: Avista Triple-E Report , January 1, 2007—December 31, 2007

Table C-5. Avista Program Benefits

Net Benefit Inputs				Var.
Resource savings	Units		$	
Energy (MWh)	—	$	30,813,091	
Peak demand (kW)	—		—	
Total electric	—	$	30,813,091	
Natural gas (MMBtu)	—	$	(355,426)	
Total resource savings		$	30,457,665	S
Participant bill savings	Electric	$	28,782,475	B
	Gas	$	(630,028)	
Monetized emission savings	Tons			
NO_x	—		—	
SO_x	—		—	
PM_{10}	—		—	
CO_2	—		—	
Total emissions		$	—	E
Non-monetized emissions (externalities)	Tons			
NO_x	—		—	
SO_x	—		—	
PM_{10}	—		—	
CO_2	—		—	
Total emissions			—	EXT
Non-energy benefits		$	12,595,276	NEB

Source: Avista Triple-E Report , January 1, 2007—December 31, 2007

Table C-6. Avista Program Cost-Effectiveness Test Results

Summary of Cost-Effectiveness Results			
Lifecycle costs and benefits			
Test	Cost	Benefits	Ratio
PCT	$ 11,756,376	$ 40,747,723	3.47
PAC	$ 7,286,775	$ 30,457,665	4.18
RIM	$ 36,069,250	$ 30,813,091	0.85
TRC	$ 19,043,151	$ 43,052,941	2.26
SCT	$ 19,043,151	$ 43,052,941	2.26
Costs and benefits included in each test			
PCT	= M - I	= B + NEB	
PAC	= O + I	= S	
RIM	= O + I + B	= S	
TRC	= O + M	= S + E + NEB	
SCT	= O + M	= S + E + EXT + NEB	
Assumptions for levelized calculations			
Average measure life		14	
WACC		8.50%	
Discount factor for savings		57%	

Source: Avista Triple-E Report , January 1, 2007—December 31, 2007

Puget Sound Energy Commercial/Industrial Retrofit Program

Puget Sound Energy's (PSE's) Commercial/Industrial Retrofit Program encourages customers to use electric and natural gas efficiently by installing cost- and energy-efficient equipment, adopting energy efficient designs, and using energy-efficient operations at their facilities. In addition, incentives are available for fuel switch measures that convert from electric to natural gas while serving the same end use. Applicable Commercial and Industrial Retrofit measure category headings include, but are not limited to: HVAC and refrigeration, controls, process efficiency improvements, lighting improvements, building thermal improvements, water heating improvements, and building commissioning.

Customers provide PSE with project costs and estimated savings. Customers assume full responsibility for selecting and contracting with third-party service providers. Projects must be approved for funding prior to installation/implementation. Maximum grants for hardware changes are based on PSE's cost-effectiveness standard. Grants for projects are made available as a percentage of the measure cost. Electric and gas measures may receive incentive grants up to 70 percent of the measure cost where the grant incentive does not exceed the cost-effectiveness standard minus program administration costs. Measures exceeding the cost-effectiveness standard will receive grants that are on a declining scale and will be less than 70 percent of the measure cost. Electric and gas measures that have a simple payback of less than a year are not eligible for a grant incentive.

Unlike the other programs presented in this document, PSE shows a positive RIM. A positive RIM is possible in the Pacific Northwest because of the allocation of low-cost hydro generation from the Bonniville Power Administration to municipal utilities. In some cases the marginal cost of avoided generation is determined by higher-cost thermal generation and is higher than the utility's average retail rate.

Table C-7. PSE Program Costs

Cost Inputs			Var.
Program overhead			
Program administration	$	2,745,048	
Marketing and outreach		—	
Rebate processing		—	
Research and development		—	
Evaluation, measurement, and verification		—	
Shareholder incentive		—	
Other		—	
Total program administration	$	2,745,048	O
Program incentives			
Rebates and incentives	$	9,914,463	
Direct installation costs		—	
Upstream payments		—	
Total incentives	$	9,914,463	I
Total program costs	$	12,659,511	
Net measure equipment and installation	$	25,103,588*	M

Source: Data provided by Laura Feinstein at PSE

* Total value

Table C-8. PSE Program Benefits

Net Benefit Inputs				Var.
Resource savings	Units		$	
Energy (MWh)	775,469	$	50,465,421	
Peak demand (kW)	—		—	
Total electric	—	$	50,465,421	
Natural gas (MMBtu)	661,480	$	2,575,451	
Total resource savings		$	53,040,873	S
Participant bill savings	Electric	$	33,297,727	B
	Gas		—	
Monetized emission savings	Tons			
NO_x	—		—	
SO_x	—		—	
PM_{10}	—		—	
CO_2	1,576,374		—	
Total emissions		$	—	E
Non-monetized emissions (externalities)	Tons			
NO_x	—		—	
SO_x	—		—	
PM_{10}	—		—	
CO_2	—		—	
Total emissions			—	EXT
Non-energy benefits		$	—	NEB

Source: Data provided by Laura Feinstein at PSE.

Table C-9. PSE Program Cost-Effectiveness Test Results

Summary of Cost-Effectiveness Results

Lifecycle costs and benefits

Test	Cost	Benefits	Ratio
PCT	$ 25,103,588	$ 43,212,190	1.72
PAC	$ 12,659,511	$ 53,040,873	4.19
RIM	$ 45,957,238	$ 53,040,873	1.15
TRC	$ 27,848,636	$ 53,040,873	1.90
SCT	$ 27,848,636	$ 53,040,873	1.90

Costs and benefits included in each test

PCT	= M	= B + I
PAC	= O + I	= S
RIM	= O + I + B	= S
TRC	= O + M	= S + E
SCT	= O + M	= S + E + EXT + NEB

Estimated levelized costs and benefits

Test	Cost $/kWh	Benefits $/kWh
PCT	$0.05	$0.09
PAC	$0.03	$0.11
RIM	$0.10	$0.11
TRC	$0.06	$0.11
SCT	$0.06	$0.11
Test	**Cost $/MMBtu**	**Benefits $/MMBtu**
PCT	$3.22	$5.54
PAC	$1.62	$6.80
RIM	$5.90	$6.80
TRC	$3.57	$6.80
SCT	$3.57	$6.80

Assumptions for levelized calculations

Average measure life	14
WACC	8.50%
Discount factor for savings	57%

Source: Data provided by Laura Feinstein at PSE

National Grid MassSAVE Program

The Massachusetts MassSAVE program is a residential conservation program targeting electricity and natural gas savings. The data shown in the tables that follow are taken from the National Grid 2006 Energy Efficiency Annual Report, submitted to the Massachusettes Department of Energy Resources and Department of Public Utilities in August 2007.

In the residential sector, there are diminishing energy savings available from single-measure incentive programs, in part due to federal appliance and lighting standards, as well as rapid progress in increasing the market penetration of CFLs relative to incandescent lighting. As a result, more utilities are seeking to develop program models that tackle harder-to reach opportunities and offer more comprehensive savings. National Grid's Home Performance with ENERGY STAR is one such program model. This program offers comprehensive whole-house improvements (insulation, air sealing, duct sealing, and HVAC improvements) for homeowners. Customers receive in-home services, step-by-step guidance, incentives for energy measures, quality installations and inspections, and low-interest financing.

Since contractors that deliver home performance services are in short supply in most markets, an infrastructure building phase is typically needed. During the initial two- to three-year startup phase, program costs may be high relative to energy savings. However, as contracting services increase over time, energy savings tend to increase dramatically. Limiting cost-effectiveness tests to three-year program cycles or less may inadvertently limit the development of these long-term, comprehensive program models. National Grid was able to reduce administrative costs associated with contractor recruitment, training, and quality assurance by limiting contractor participation in program startup and by requiring participating contractors to directly install some measures.

Comprehensive, whole-building program models such as Home Performance with ENERGY STAR may face a number of additional challenges using commonly employed practice for calculating cost-effectiveness. For example, installing air sealing and insulation reduce heating and cooling loads, which reduces the savings associated with installing efficient HVAC equipment (interactive effects; see Section 3.2.1). However, reduced heating and cooling loads can also provide opportunities for downsizing heating and cooling systems, which are not captured by the cost-effectiveness tests. Furthermore, whole-house improvements provide a variety of non-energy benefits (Section 4.9) that can be difficult to quantify and are often not included as benefits in the cost-effectiveness tests.

More information can be found online at <http://www.masssave.com/customers/>.

Table C-10. National Grid Program Costs

Cost Inputs			Var.
Program overhead			
Program administration	$	760,324	
Marketing and outreach	$	296,628	
Rebate processing		—	
Research and development		—	
Evaluation, measurement, and verification	$	134,077	
Shareholder incentive		—	
Other		—	
Total program administration	$	1,191,029	O
Program incentives			
Rebates and incentives	$	3,507,691	
Direct installation costs		—	
Upstream payments		—	
Total incentives	$	3,507,691	I
Total program costs	$	4,698,720	
Net measure equipment and installation	$	2,452,985	M

Source: Data provided by Lynn Ross at National Grid

Table C-11. National Grid Program Benefits

Net Benefit Inputs				Var.
Resource Savings	Units		$	
Energy (MWh)	46,385	$	2,550,000	
Peak demand (kW)	6,921		3,328,000	
Total electric	—	$	*5,878,000*	
Natural gas (MMBtu)	655,547		6,506,048	
Total resource savings		$	12,384,048	S
Participant bill savings	Electric	$	679,800	B
	Gas		—	
Monetized emission savings	Tons			
NO_x	7		—	
SO_x	19		—	
PM_{10}	—		—	
CO_2	1,576,374		—	
Total emissions		$	—	E
Non-monetized emissions (externalities)	Tons			
NO_x	—		—	
SO_x	—		—	
PM_{10}	—		—	
CO_2	—		—	
Total emissions			—	EXT
Non-energy benefits		$	155,601	NEB

Source: Data provided by Lynn Ross at National Grid.

Table C-12. National Grid Program Cost-Effectiveness Test Results

Summary of Cost-Effectiveness Results

Lifecycle costs and benefits

Test	Cost	Benefits	Ratio
PCT	$ 2,452,985	$ 4,187,491	1.71
PAC	$ 4,698,720	$ 12,384,048	2.64
RIM	$ 5,378,520	$ 12,384,048	2.30
TRC	$ 7,151,705	$ 12,384,048	1.73
SCT	$ 7,151,705	$ 12,539,649	1.75

Costs and benefits included in each test

PCT	= M	= B + I
PAC	= O + I	= S
RIM	= O + I + B	= S
TRC	= O + M	= S + E
SCT	= O + M	= S + E + EXT + NEB

Estimated levelized costs and benefits

Test	Cost $/kWh	Benefits $/kWh
PCT	$0.04	$0.06
PAC	$0.07	$0.18
RIM	$0.08	$0.18
TRC	$0.10	$0.18
SCT	$0.10	$0.18
Test	**Cost $/MMBtu**	**Benefits $/MMBtu**
PCT	$2.79	$4.76
PAC	$5.34	$14.08
RIM	$6.11	$14.08
TRC	$8.13	$14.08
SCT	$8.13	$14.26

Assumptions for levelized calculations

Average measure life	8
WACC	8.50%
Discount factor for savings	70%

Source: Data provided by Lynn Ross at National Grid

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Intelligent Energy Choices for Kentucky's Future

Kentucky's 7-Point Strategy for Energy Independence

Kentucky UNBRIDLED SPIRIT

GOVERNOR STEVEN L. BESHEAR

November 2008

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Foreword

"Kentucky can be a national leader in energy technology and production. We can help the country move toward greater energy self-reliance. I intend to put us on such a path."

Governor Steven L. Beshear, March 6, 2008

This challenge to all Kentuckians serves as the launching pad to deliver a progressive, integrated energy plan for the commonwealth.

As the third largest producer of coal in the United States, Kentucky's challenge, our challenge, for the 21st century is to pragmatically adopt inherently cleaner, newer energy sources as well as innovative uses of traditional energy sources. Kentucky can be – and in fact must be – a leader in this energy revolution. We are not alone in this effort.

This bold document, *Intelligent Energy Choices for Kentucky's Future*, is the beginning of an evolutionary plan for our state. It is an energy plan that will improve the quality of life for all Kentuckians by simultaneously creating efficient, sustainable energy solutions and strategies; by protecting the environment; and by creating a base for strong economic growth.

Kentucky's plan incorporates recommendations to improve energy efficiency for Kentucky's homes, businesses and transportation fleet. It provides a framework from which we can begin to increase our use of renewable energy sources. It discusses the potential for biofuels as well as coal-to-liquids and coal-to-gas technologies. It recommends the initiation of an aggressive carbon capture/sequestration program for coal-generated electricity. It provides a discussion of how Kentucky could initiate and grow safe and reliable nuclear power for electricity generation in Kentucky.

By refining and adopting this energy plan, the Commonwealth of Kentucky hopes to establish leadership in the United States for innovating and creating efficient, sound and environmentally compatible energy solutions and strategies. Every journey has a destination. This plan is a road map for a journey to energy independence. We will know we have reached our destination when we have accomplished six important things:

- Conserve and use energy more efficiently.
- Achieve energy independence for transportation fuels.
- Use coal more cleanly and efficiently.
- Diversify electricity generation to optimize use of renewable and alternative fuels, in addition to coal, *Kentucky's leading fossil fuel, and nuclear.*
- Mitigate carbon dioxide emissions, reducing our carbon footprint.
- Establish Kentucky state government as a leader in green practices.

As part of these proposals, we must have broad discussions of our options, alternatives, benefits and priorities for our state. It is paramount that we realize the consequences of doing nothing – consequences for our generation and the generations of Kentuckians to come.

We must contend with the reality that our state's energy policy will be increasingly shaped by decisions at the national level. These national decisions will undoubtedly accelerate energy development and independence within the guidelines of environmental protection as a national priority. It is imperative that we have policies and programs in place that allow Kentuckians to protect and utilize our energy resources in an environmentally sound manner and help us to achieve energy independence. The tenets and spirit of this vital strategic plan will help us do that.

Steven L. Beshear, Governor

Leonard K. Peters, Secretary
Energy and Environment Cabinet

Executive Summary

KENTUCKY'S CHALLENGE for the 21st century is to develop clean, reliable, affordable energy sources that help us improve our energy security, reduce our carbon dioxide emissions, and provide economic prosperity. Kentucky can be – and in fact must be – a leader in this energy revolution.

Energy independence is a top challenge to the state and the nation in the 21st century, a challenge that has been made at once more urgent and more complex by the equally pressing issue of global climate change. For a major coal-producing state that also relies on coal to generate more than 90 percent of its electricity, addressing these two issues – energy security and climate change – is especially problematic.

We have to contend with the reality that, going forward, our state's energy policy will be increasingly shaped by decisions at the national level, decisions which in turn are being driven by significant global issues and events. As a state, it is imperative that we have policies and programs in place that allow us to shape our own energy future by making sure we utilize our energy resources in an environmentally sound manner. This strategic action plan, *Intelligent Energy Choices for Kentucky's Future*, is intended to place Kentucky on such a path.

Intelligent Energy Choices is an action plan for our state that is intended, first and foremost, to improve the quality and security of life for all Kentuckians by creating efficient, sustainable energy solutions and strategies; by protecting the environment; and by creating a base for strong economic growth over the long term. We must make changes in order to accomplish these objectives. In addition to identifying new initiatives, the plan provides an important framework around existing policies and activities so that we can aggressively increase our use of renewable energy sources; improve the energy efficiency of our homes and buildings; develop cleaner methods to utilize our fossil energy resources; diversify our electricity and transportation energy portfolios; and more fully integrate our agricultural and energy economies.

Intelligent Energy Choices is designed to be a 'living' document that serves as a means for the state – the general public, public officials, educators, business and industry at all levels, and others – to craft a consensus for a comprehensive, holistic energy plan for the betterment of all. It is an evolutionary plan that is not intended to be exhaustive at the outset. We cannot address every single issue in this relatively comprehensive document; thus, there will be additional issues that need action on a case-by-case basis. We have made a concerted effort to include all the highest priority actions that will serve as an underpinning, a foundation, for great progress and for future actions through 2025.

Kentucky Must Act Now

Kentucky's energy use is projected to grow by slightly more than 40 percent between now and 2025 under a Business-As-Usual scenario. This energy growth encompasses all sectors, including electricity generation, natural gas use, and transportation fuels. For example, between now and 2025, according to estimates from the Kentucky Public Service Commission, Kentucky will need an additional 7,000 megawatts of electricity generation (PSC, 2005).

Intelligent Energy Choices is designed to lead to a much more diversified energy portfolio for the commonwealth and provide economic, environmental and energy security benefits. In the future, primarily relying on one source of power for electricity generation will not be prudent in the face of imminent climate change legislation at the federal level. While we anticipate retrofits of existing power plants for carbon dioxide capture, our electricity generation must be diversified to include renewables and other sources, such as nuclear power.

This plan allows us to develop flexibility in our energy portfolio so that we can take timely advantage of technological advances in such areas as cellulosic biofuels, solar and wind, and carbon management. A diverse portfolio gives us the flexibility to effectively utilize lower carbon-emitting technologies and fundamentally more environmentally benign energy solutions.

Just as we will experience growth in our demand for energy, our greenhouse gas (GHG) emissions will escalate if we continue down the same path. With such a high reliance on fossil fuels, Kentucky's projected GHG emissions could be more than 40 percent higher than they are today if we do not take action. With implementation of the seven proposed strategies, however, our GHG emissions will be more than 50 percent lower in 2025 than they would otherwise be. More significantly, GHG emissions in Kentucky will actually be 20 percent lower in 2025 than were our 1990 emissions (Figure ES-1).

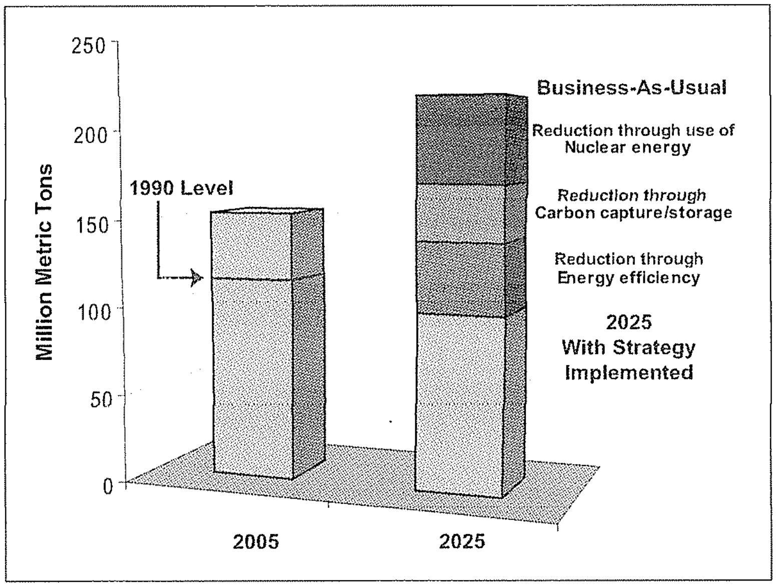

Figure ES-1: Reductions In Carbon Dioxide Emissions

Relying on coal-fired power generation in the state will not be sufficient to support Kentucky's coal industry if other states cease purchase of Kentucky coal. By diversifying the coal industry's product line into transportation fuels and synthetic natural gas, we support our efforts to become less vulnerable to imports and ensure a continued market for Kentucky coal, sustaining the 17,000 plus jobs in the coal industry, as well as the industry's other economic effects.

Kentucky's Plan Outlines Seven Strategies

The plan proposes a Renewable and Efficiency Portfolio Standard (REPS) whereby 25 percent of Kentucky's energy needs in 2025 will be met by reductions through energy efficiency and conservation and through use of renewable resources. *Strategies 1, 2, and 3* are designed to help the commonwealth achieve the REPS. Leading with energy efficiency, conservation, and renewable energy allows us to implement actions to reduce energy use and carbon dioxide emissions in a timely and cost-effective manner. However, even with an aggressive REPS, Kentucky will still need to look at our traditional energy source – coal, with an expanded cleaner product line – *and other options such as nuclear.*

Our growing reliance on imported oil presents economic and security threats that are untenable. Therefore, the plan also proposes an Alternative Transportation Fuel Standard (ATFS) to help us transition away from dependence on foreign petroleum. Kentucky can displace 60 percent of its reliance on foreign petroleum by utilizing fuels such as those derived from biomass and coal, plug-in hybrid vehicles, and compressed natural gas (CNG), and we can do this by building upon our existing infrastructure. Elements of the ATFS are captured in *Strategies 1* (plug-in hybrids), *3* (biofuels) and *4* (coal-to-liquids and natural gas).

Equally important as weaning the state from imports of foreign oil is reducing our dependence on imported natural gas. *Strategy 5* establishes an action plan directed toward increased natural gas production in the commonwealth and production of synthetic natural gas from Kentucky's coal resources.

To achieve our greenhouse gas reduction goals, deployment of carbon dioxide capture and storage technologies on a large scale is crucial. The action plan in *Strategy 6* will help Kentucky initiate aggressive carbon capture and storage projects, with a goal that by 2025, 50 percent of Kentucky's coal-based energy facilities will be equipped with carbon management technologies.

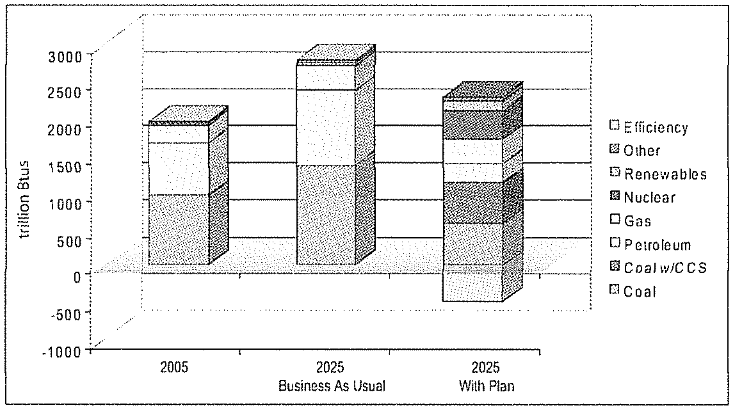

Figure ES-2: Kentucky's Total Energy Use

A final key component to reducing Kentucky's carbon dioxide emissions is deploying non-carbon dioxide emitting technologies to meet our baseload electricity generation needs in the future. One option that must be considered is nuclear power. *Strategy 7* provides an important discussion of the environmental, security and economic issues surrounding nuclear power.

Figure ES-2 summarizes Kentucky's current energy demand and what can be accomplished with this plan. The bar charts show the current energy mix, what it will look like in a Business-As-Usual scenario, and how this plan will provide a much more flexible and effective energy portfolio.

Following is an overview of the goals and actions of each of the seven strategies. It is important to note that *Strategies 1, 2 and 3*, as part of the Renewable and Efficiency Portfolio Standard, form a three-part vision to provide 25 percent of Kentucky's energy needs by 2025 through energy efficiency, renewable energy and biofuels. Additionally, *Strategies 1, 3, and 4*, as part of an Alternative Transportation Fuel Standard, are part of a goal to reduce Kentucky's dependence on imported oil by 60 percent by 2025.

Strategy 1: Improve the Energy Efficiency of Kentucky's Homes, Buildings, Industries, and Transportation Fleet

Kentucky has been a high user of energy largely because of our historically low electricity rates. We have had little incentive to conserve, and thus we are over-users. This must change. Kentucky can achieve its greatest and most cost-effective reduction in GHG emissions through energy *efficiency in all sectors: residential, commercial, industrial and transportation. We can forestall construction of some additional generation facilities through energy efficiency. Therefore, our leading strategy, and our utmost advantage in achieving the overall objectives of this plan, is greater energy efficiency.*

Goal: Energy efficiency will offset at least 18 percent of Kentucky's projected 2025 energy demand.

Both nationally and worldwide, we are experiencing dramatic increases in costs for our traditional nonrenewable sources of energy – coal, natural gas and petroleum. It is likely that the prices for these global commodities will continue to increase, and therefore consumers' energy bills will continue to rise. Most would agree that the era of cheap energy is over. The choice we face is to take no action and see large price increases with limited economic security, or to take prudent actions now and realize a better chance for smaller price increases as well as increased economic security. In the near term, energy efficiency and conservation represent the fastest, cleanest, most cost-effective, and most secure methods we have to reduce our growing demand for energy and to help us address issues surrounding global climate change.

Actions to Achieve the Goal

- An Energy Efficiency Resource Standard (EERS) will be established to support the energy efficiency portion of the REPS with a goal of reducing energy consumption by at least 16 percent below projected (with no changes) 2025 energy consumption. To achieve the EERS a combination of both utility-sponsored and non-utility-sponsored energy efficiency programs will be developed and implemented.
- Transportation energy efficiency programs will contribute another two percent reduction representing energy savings corresponding to approximately 500 million gallons of motor fuel annually. Elements of this component of *Strategy 1* support the objectives of the ATFS.
- Kentucky will initiate strong education, outreach and marketing programs that will support all energy efficiency activities.
- An energy efficiency program will also be established for state government that has aggressive internal energy savings targets. This program is important as it establishes a leadership role for state government, and creates many new, well informed energy efficiency advocates for Kentucky.

Strategy 2: Increase Kentucky's Use of Renewable Energy

Kentucky currently relies on renewable resources for less than three percent of its electricity generation. The commonwealth has the 5th largest hydro power production east of the Mississippi, and several of our utilities are utilizing landfill gas for electricity generation. The potential to increase both of these resources, especially through landfill gas, is encouraging. However, with today's technologies, our ability to use some resources such as wind and solar for baseload generation is limited in Kentucky. As technologies advance in the next few decades, this scenario can change. In the meantime, especially as part of the utility resource planning process, Kentucky *should aggressively pursue its options for renewable generation in order to achieve greenhouse gas reductions and diversify our energy portfolio.*

Goal: By 2025, Kentucky's renewable energy generation will triple to provide the equivalent of 1,000 megawatts of clean energy while continuing to produce safe, abundant, and affordable food, feed and fiber.

Kentucky does have supplies of non-fossil natural resources that can help contribute to a clean and secure energy future, natural resources such as wind, solar, hydropower, biomass and methane. Energy from renewable resources benefits the environment while creating economic opportunities – the "green collar" jobs for businesses, industries and rural communities. To achieve this goal, the commonwealth must aggressively invest in the development of its renewable energy resources.

Actions to Achieve the Goal

- State government will lead by example by requiring new or substantially renovated public buildings to use renewable energy as a percentage of total energy consumption. The requirements will escalate over time to reflect the state's renewable energy and energy efficiency goals. The High Performance Building Committee established in House Bill 2 (2008 regular session) will establish renewable energy targets for 2012, 2018, and 2025 for new or substantially renovated buildings.
- Kentucky's Energy and Environment Cabinet (EEC) will recommend policies and incentives necessary to achieve the state's renewable energy goal. The analysis will include implementation plans for the REPS for Kentucky's electric utilities.
- As Kentucky's forest resources can potentially contribute more than 50 percent of Kentucky's renewable energy potential, the state will review its policies and regulations to encourage the responsible, sustainable use of woody biomass within the guidelines of environmental protection.

Strategy 3: Sustainably Grow Kentucky's Production of Biofuels

Kentucky currently uses only five to 10 percent of its potential biomass resources for the production of biofuels such as ethanol and biodiesel. Kentucky can significantly grow its agricultural and forestry resources in an environmentally and economically sustainable way to provide more biofuels for transportation, particularly as biofuel technologies expand in the next decade. We can thereby strengthen our energy security while growing and diversifying our agricultural and forestry economies, as well as reducing our GHG emissions. Through a concerted effort and collaboration with agricultural producers, researchers at universities, and policy makers, Kentucky can grow its biofuels industry to meet 20 percent of our current transportation fuel needs.

Goal: By 2025, Kentucky will derive from biofuels 12 percent of its motor fuels demand (775 million gallons per year, which represents approximately 20 percent of Kentucky's current transportation fuels demand), while continuing to produce safe, abundant, and affordable food, feed, and fiber.

As part of the ATFS, *Strategy 3* focuses on research and development (R&D) as well as deployment of commercial-scale facilities to address technical or infrastructure challenges, thereby enhancing the potential to grow the biofuels market. Kentucky will begin a statewide initiative to ensure that the needed infrastructure, human resources, research and development support, and policies are in place to enable meaningful and sustainable growth in biofuels. Current studies indicate there could be a nearly 10-fold increase in current bio-based fuels in Kentucky.

Actions to Achieve the Goal

- Kentucky will invest in algae and other non-food crops as a feedstock for biodiesel.
- Kentucky will aggressively seek federal support for and invest in ventures that promote a market for ethanol from non-traditional feedstocks, especially feedstocks that do not negatively affect food prices or availability.
- Kentucky will establish an escalating renewable fuel standard (RFS) for the state vehicle fleet.
- Incentives will be created to encourage production, distribution, and demand for biofuels in Kentucky in an environmentally sustainable manner.

Strategy 4: Develop a Coal-to-Liquids Industry in Kentucky to Replace Petroleum-Based Liquids

Energy independence and economic security are major objectives of this plan for Kentucky and for the United States. Volatile petroleum prices beyond our control promise to rise again as the economy recovers. The United States imports 60 percent of its petroleum, largely from unstable regions in the Middle East and South America. But, Kentucky has abundant coal resources and is the third largest coal producer in the United States. The high emissions of carbon dioxide into the environment must be addressed now, as the United States moves toward federal mandates and penalties for coal-fired power generation. Kentucky can diversify ultimate coal utilization, producing cleaner and more efficient energy for state and domestic use. Coal-to-liquid and coal-to-gas technologies can replace petroleum-based liquids and imported natural gas, respectively.

Goal: Kentucky will develop a coal-to-liquids (CTL) industry that will use 50 million tons of coal per year to produce four billion gallons of liquid fuel per year by 2025.

With its vast coal resources, proven support from elected officials, and dedicated research and development program, Kentucky is uniquely positioned to develop a CTL industry that can serve as an engine for economic growth, while helping to reduce our dependence on foreign oil. The actions in *Strategy 4* further support the implementation of the state's ATFS.

Actions to Achieve the Goal

- Kentucky will sanction two 500 million-gallon per year (approximately 35,000 barrels per day) CTL fuel facilities in both 2013 and 2014, and then two additional 480 million-gallon per year CTL fuel facilities by 2018, and two more by 2025, for a total of eight new CTL facilities.
- To ensure that trained personnel are available to staff increased coal consumption required by the CTL industry, Kentucky's EEC will work with the Community and Technical College System to

identify appropriate training programs. To achieve the required employment levels, increased training capabilities should be available within the next three years.

- Kentucky will evaluate its current coal mining capabilities to ensure that it can achieve the necessary levels of coal production to support both coal-fired electricity generation and the development of a CTL industry in the near-term.

Strategy 5: Implement a Major and Comprehensive Effort to Increase Gas Supplies, Including Coal-to-Gas in Kentucky

Today, about 44 percent of Kentucky's total natural gas requirements are met by in-state production; the remainder is imported. The same threats of volatile prices and unstable sources apply to our increasing dependence on imported natural gas, just as they do on our imported oil. Moreover, being largely dependent on external sources of natural gas, Kentucky's consumers pay added transportation costs for the gas we use. As utilities increase the use of natural gas for electricity generation, in order to comply with imminent GHG mandates, both natural gas and electricity prices will increase. We need to increase our energy independence with natural gas, also. Coal gasification technology is neither new, nor experimental. Virtually all of Kentucky's gas needs can be met if we increase our in-state natural gas production and produce synthetic natural gas derived from coal, both of which help us to achieve our overall objectives of economic security and energy independence. A strong coal-to-gas industry will build upon Kentucky's economic development and increase the number of jobs created by the coal-to-liquids industry.

Goal: Kentucky will produce the equivalent of 100 percent of our annual natural gas requirement by 2025 by augmenting in-state natural gas production with synthetic natural gas (SNG) from coal-to-gas (CTG) processing.

Being significantly dependent on external sources of gas today, consumers in Kentucky pay added transportation costs for most of the natural gas that they use. More important, consumers in Kentucky, as in other states, have become vulnerable to possible supply uncertainties and price increases and spikes as these may occur in the U.S. natural gas system and market. Virtually all of the gas needs of Kentucky can be met by increasing Kentucky's own domestic natural gas production supplemented by synthetic natural gas produced by gasifying coal.

Actions to Achieve the Goal

- Research at the University of Kentucky's Center for Applied Energy Research (CAER) should be expanded to achieve optimal processes for converting coal to gas under various combinations of coals and operating conditions.
- Research at CAER should be enhanced to include the life-cycle carbon reduction potential of gasifying biomass with coal in CTG processes.
- A Public Service Commission (PSC) administrative case should be initiated to ensure that Kentucky Local Distribution Companies and customers are not harmed by direct sales of gas from SNG producers to industrial plants.
- Assessments of new natural gas resources in Kentucky should be expanded and accelerated.

- A comprehensive study of pipeline infrastructure in Kentucky should be initiated to determine needs in relation to expanded production of Kentucky's domestic natural gas and coal-bed methane resources.

Strategy 6: Initiate Aggressive Carbon Capture/Sequestration (CCS) Projects for Coal-Generated Electricity in Kentucky

More than 90 percent of Kentucky's electricity is derived from coal-fired power, and we rank 13th in total carbon dioxide emissions. Carbon capture and sequestration (CCS) is crucial to continued use of coal as an energy resource in Kentucky. Success of CCS will determine our ability to meet our future energy needs. Currently, CCS development emphasizes geologic sequestration. We need more technical options for cost-effective carbon management so that coal can be a cleaner energy resource. Of all the technologies addressed in this plan, CCS has the greatest technological uncertainty, which is why this strategy emphasizes the need for research, demonstration, and deployment. Beyond geologic sequestration, the federal government has provided little leadership in carbon management, but will likely establish CCS as a priority in the new administration. Kentucky must protect its coal industry and initiate its own solutions to managing carbon dioxide emissions as it diversifies its product line.

Goal: By 2025, Kentucky will have evaluated and deployed technologies for carbon management, with use in 50 percent of our coal-based energy applications.

There are unique challenges to be faced in a carbon-constrained world, given Kentucky's reliance on coal-fired power generation. The threats associated with climate change will require Kentucky to make a concerted effort to control emissions of carbon dioxide, one of the greenhouse gases, while at the same time recognizing that coal will continue to be a vital component of our energy mix. We must find ways to reduce carbon dioxide emissions and meet our energy needs for the future.

Actions to Achieve the Goal

- The work of the Carbon Management Research Group (CMRG), a consortium of Kentucky's major power companies, the University of Kentucky's Center for Applied Energy Research (CAER), and the Commonwealth of Kentucky's Energy and Environment Cabinet (EEC) should be supported. The CMRG will carry out a ten-year program of research to develop and demonstrate cost-effective and practical technologies for reducing and managing carbon dioxide emissions in existing coal-fired electric power plants.
- Legal hurdles to successful CCS should be examined with recommended legislative solutions provided to the 2010 General Assembly.
- Necessary staff positions in the Division of Oil and Gas should be funded to support Kentucky's primacy over the underground injection control permitting program.
- The EEC should work closely with university researchers and industry partners to undertake one large-scale carbon mitigation project to utilize algae to capture carbon from flue gases, and then convert the algae to biofuels.

- The Consortium for Carbon Storage, which was established by the Kentucky Geological Survey with a seed grant from the EEC should be supported. The Consortium will determine the potential for sequestration and for enhanced oil and gas recovery and enhanced coal-bed methane recovery using carbon dioxide.

Strategy 7: Examine the Use of Nuclear Power for Electricity Generation in Kentucky

With major increases in efficiency and conservation, aggressively utilizing alternative and bio-based energy sources, and more effective use of cleaner coal technologies, we still will not be able to achieve the projected energy demands in 2025 along with meaningful GHG reductions. Thus, other sources of base-load electricity generation will be necessary. Many of our neighboring states are considering nuclear energy. Nuclear power production has no direct carbon dioxide emissions and is already a significant component of the global energy system. Current technologies for nuclear production are superior to the previous generation of plants, complementing an already safe industry in the United States. Improved reliability and efficiency have allowed the industry to maintain its 20 percent share of the growing U.S. electricity market. While the issue of disposal of spent fuel has not been completely resolved, progress will continue to be made to arrive at a solution that addresses the nation's needs.

Goal: Nuclear power will be an important and growing component of the nation's energy mix, and Kentucky must decide whether nuclear power will become a significant part of meeting the state's energy needs by 2025.

In a carbon constrained world, the interdependencies among energy, the environment and the economy will lead to broad sweeping economic transformations in the 21st century. To find solutions that address climate challenges, use our abundant natural resources to gain energy security, and provide the power needed to drive our economy will require pursuit of a diversified mix of energy options. In weighing the benefits and limitations of potential solutions we must be willing to fully assess and understand the societal, technical, and financial trade-offs involved. Nuclear power is one such option that deserves our full attention, as its technology and safety have significantly improved in the last three decades. It also is likely to become a national priority.

Actions to Achieve the Goal

- Legal hurdles to successful inclusion of nuclear power in Kentucky's energy mix should be examined. Specifically, removal or revision of the legislative ban on new nuclear power plants must be addressed.
- A public engagement plan should be implemented to gather and address stakeholder feedback and concerns and to provide education about nuclear power today.
- Research should be conducted to assess the desirability of co-locating nuclear power plants with advanced coal conversion plants to assess the effects on reducing carbon dioxide emissions, providing ready access to electricity and/or steam, and possibly using waste heat for the coal conversion process.
- Incentives that reduce the risk of capitalizing and financing a new power plant should be considered in developing these programs.

- The EEC should work with the Community and Technical College System to ensure that trained personnel are available to staff the construction and operation of nuclear power plants.
- The state universities should explore now the possibility of adding nuclear engineering, health physics, and radiological science programs to their curricula.

Conclusion

An overarching goal of this action plan has been to identify and address those actions that can be implemented in sufficient time to help citizens and businesses prepare for the inevitable changes that will occur in the national and global energy landscape in the years ahead. The scientific community worldwide and global consortia are concerned that we must act immediately to reduce the impact of *greenhouse gases on global warming. Environmental protection includes intelligent use of land as well* as nonrenewable and renewable resources. This thoughtful strategy will help Kentucky ensure the viability of two signature industries – our mining and agricultural industries – while addressing the global issue of climate change and, at the same time, allowing new vibrant industries that provide high-paying, quality jobs to flourish.

For Kentucky to be a national energy leader, we must fully integrate the development of our energy resources with our mission to protect the environment. Therefore, these strategies address measures to utilize our coal resources in a cleaner, more efficient manner, and in a way that will help us assure energy security. In fully utilizing our biomass, solar, wind, hydro and other renewable energy resources, we not only strengthen our energy and economic security – by diversifying our electricity and transportation fuels portfolios – but we also help the state reduce its carbon dioxide and other greenhouse gas emissions and other pollutants in a significant way. The seven strategies, when implemented, will restructure our energy portfolio in such a way that we can use energy in its broadest sense as a tool for economic development, which Kentucky desperately needs.

With this action-oriented energy plan, by 2025 Kentucky will accomplish the following:

- Provide 30,000-40,000 new Kentucky jobs as a result of a booming diversified energy sector – at least 12,000 directly in our new energy producing sector (3,500 from coal-to-liquids production; 1,800 producing fuels from biomass; 1,700 at coal-to-gas facilities; 4,400 at nuclear plants; and 1,000 at other "green collar," or renewable energy, industries), and another 20,000-25,000 jobs as a result of the domino effect – jobs which provide indirect support to the new booming energy industry. The increase assumes sustaining current employment, maintaining annual coal production in Kentucky at current levels, with coal mining employment at 17,000.
- Achieve energy independence for Kentucky from imported oil.
- Produce annually approximately four billion gallons of liquid fuels from coal (utilizing about 50 million tons of coal annually).
- Produce annually 135 billion cubic feet of synthetic gas from coal (utilizing about nine million tons of coal annually) to augment Kentucky's natural gas supply.
- *Reduce the net per capita carbon emissions into the atmosphere by 50 percent, while ensuring* Kentucky's economic viability by protecting Kentucky's coal industry against negative impacts of federally mandated carbon management legislation. This will be accomplished by the combination of implementing the carbon capture and sequestration possibilities as determined by the research conducted in *Strategy 6*, and building nuclear and renewable generating capacities as

described in *Strategies 2 and 7*. The mix of nuclear power, renewable energy, coal-to-liquids and coal-to-gas production, and reduced coal-fired electricity generation will enable compliance with federal mandates while increasing the use of Kentucky's home-grown and most abundant energy resource, coal.

- Optimize our renewable energy resources, utilizing wind, solar, hydropower, landfill gas, and biomass.
- Maintain current energy per capita use despite major energy growth requirements.

Should we fail in these efforts, by 2025 we will be using over 40 percent more energy; paying 20 to 50 percent more for each unit of energy purchased; still bemoaning our reliance on foreign sources of energy; facing a declining coal industry; and finding ourselves captive to limited economic development opportunities.

If we succeed, we shall have produced greater economic and energy security for all Kentuckians, while creating significant job growth and economic development in a wide diversity of agricultural, energy, high tech and service companies; a cleaner and healthier environment; a reduction in Kentucky's contribution to global warming; greater energy efficiencies and independence; and a more substantial corporate tax base to support higher quality healthcare, education and transportation for all of us throughout the Commonwealth of Kentucky.

Introduction

Kentucky Advances in the 21st Century

Kentucky's, and the nation's, prosperity depends on having a reliable supply of clean, sustainable energy now and far into the future. Addressing energy needs and energy conservation is not new. Many remember the issues we faced in the 1970s when the oil embargo crippled our state and the nation. Those issues are heightened today and affect our economic and energy security. Rising oil and natural gas prices have startled consumers, who are actively seeking solutions.

What differentiates the national mood of the 1970s from today are four key issues, all of which are addressed throughout this strategic document.

- Global warming is a known and must be addressed.
- In a global economy, the United States alone controls neither energy prices, nor supply and demand.
- Kentucky's electricity energy infrastructure requires major rebuilding over the next 20 years.
- National security is directly tied to how energy independent we can become.

As stated in a 2007 report by the World Resources Institute, "It now seems certain that climate change *and energy security are two of the greatest challenges the global community faces in the 21st century.* Energy policies designed to address one of these challenges alone can have unintended and often negative consequences on the other" (World Resources Institute, 2007).

Climate Change Dictates New Best Practices

Today, few still debate the primary cause of climate change. The debate continues, however, about how to implement effective policies designed to help us reduce the cause of climate change. Climate change is already affecting U.S. water and land resources, agriculture, and biological diversity, necessitating corrective actions and the utilization of new resources.

As a major coal-producing state that relies on coal to generate more than 90 percent of its electricity, addressing these two paramount issues, energy security and climate change, is problematic. Kentucky's long-standing support of an industry that provides more than 17,000 high-wage jobs and that brings in more than $3 billion from out-of-state sales is increasingly being questioned by some who argue that coal is a 20th century energy source. Thus, while we are blessed with abundant coal resources, we must also contend with the implications of using these resources in a world of likely limitations on the emissions of carbon dioxide, a primary greenhouse gas (GHG). Nationwide, coal provides slightly more than 50 percent of the electricity needs, while coal-fired generation accounts for 81 percent of GHG emissions.

Federal legislation imposing limits on GHG emissions did not make it out of the 110th session of Congress; however, most observers agree that such legislation is a matter of when, not if. America's proposed Climate Security Act of 2007, known as the Lieberman-Warner bill, would have cut GHG emissions by two-thirds by the year 2050, largely by means of a cap-and-trade system. The cap would have covered 87 percent of U.S. GHG emissions from the electric power, transportation, and industrial sectors (including natural gas processors and importers and petroleum processors and refiners). Whatever federal legislation is ultimately enacted, we can anticipate that it will have GHG reduction goals similar to the Lieberman-Warner proposal.

Financial Markets Respond to Climate Risks

With GHG legislation a near certainty in the future, Wall Street banks have announced that GHG emissions will factor into their willingness to loan money for building power plants. In February 2008, three of the world's leading financial institutions announced the formation of The Carbon Principles — guidelines on climate change for advisors and lenders to power companies in the United States. The institutions created the Principles as a result of the risks faced by the power industry as utilities, independent producers, regulators, lenders and investors deal with the uncertainties around regional and national climate change policy. If high carbon dioxide-emitting technologies are selected by power companies, the signatory banks have agreed to factor these risks and potential mitigation strategies into the final financing decision.

Kentucky Acknowledges Climate Change's Impact on Coal-Fired Electricity Generation

Kentucky is the third largest coal-producing state (Wyoming is first and West Virginia second). Kentucky accounts for roughly one-tenth of total U.S. coal production and nearly one-fourth of U.S. coal production east of the Mississippi River. With Kentucky's historic reliance on coal-fired base load generation, the state has enjoyed some of the lowest electricity rates in the country. Our low rates have allowed energy-intensive industries to flourish in the state. Our low rates have also encouraged Kentuckians to become some of the greatest consumers of electricity in the country. Kentucky's per capita consumption of residential electricity is among the highest in the United States (Energy Information Administration, 2006).

Kentucky's electric power industry emitted more than 93 million metric tons of carbon dioxide in 2006, and the state was ranked seventh in the United States in per capita emissions and 13th in overall carbon dioxide emissions (3.8 percent of the U.S. total). In May 2008, a Brookings Institute report identified Lexington as having the highest per capita carbon footprint in the United States, and Louisville as one of the top five emitters. The Brookings report primarily implicated coal-fired electricity generation for the high carbon footprint of these two cities.

According to a 2007 U.S. Energy Information Administration (EIA) report, electric utilities will account for the vast majority of emissions reductions under any Congressional GHG legislation. The EIA reports that power plants will account for between 80 and 90 percent of such reductions by 2030. According to the report, the decline in power-plant emissions would reflect reduced reliance on coal, with usage as much as 62 percent to 89 percent below what would otherwise be the case by 2030.

The report also predicts that many existing coal-fired plants will likely be retired because it will not be practical to retrofit the facilities with capture-and-storage technology. At the same time, Kentucky's demand for electricity is projected to increase. The Kentucky Public Service Commission estimates an additional 7,000 megawatts of generating capacity will be needed by 2025, or an overall annual growth rate of 1.7 percent. The average age of Kentucky's electric generating fleet is 35 years, and therefore will lead to major changes in Kentucky's electrical energy portfolio over the next two decades. The EIA indicates that most power companies will likely increase their use of nuclear power, renewable fuels, and natural gas as a result of these pressures.

Energy Independence Means Energy Security

The United States Imports 60 percent of its Oil and Natural Gas

The United States currently imports approximately 60 percent of its petroleum, more than half of which comes from insecure or unstable regions of the world.

The EIA predicts that our dependence on imports will grow to more than 70 percent by 2025, unless the United States takes aggressive steps to develop domestic energy supplies. In its 2008 Annual Energy Outlook, the EIA also projects that worldwide demand for oil will remain high, despite very high prices for gasoline.

The United States currently imports approximately 60 percent of its petroleum, more than half of which comes from insecure or unstable regions of the world.

Many energy experts point out the normal demand response to high prices is not occurring at the international level. The demand for gasoline in the United States has relented somewhat since 2007, due to high prices, but worldwide, demand for oil and energy is strong and growing as countries are developing economically and therefore requiring larger percentages of energy inputs. This is not a short-term trend.

The International Energy Agency (IEA) estimates that global energy demand will increase 55 percent by 2030, with nearly 75 percent of that demand coming from developing countries.

Compounding this challenge, oil and gas in the ground is becoming more costly to extract. Given the crude oil price volatility we have witnessed in the past year and given that most experts expect prices to go up again once the worldwide economy rebounds, the strategies and options of the last few decades can no longer be counted upon to mitigate the economic impacts caused by sustained volatile or high oil prices. Thus, economic and energy security needs have created an overarching demand for greater energy independence, with a decided shift towards domestically available resources.

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Kentucky Plans Multilayered Strategies to Resolve Energy Issues

There is no single solution to our energy challenges. We must focus on strategies that employ all existing and emerging technologies and practices that work for Kentucky, finding new ways to utilize existing resources with the objectives of high efficiency, energy independence and the reduction of our carbon footprint. This document is not intended to be exhaustive. We do not, and cannot, address all possible actions that the commonwealth must take over the next two decades, and there will be additional important issues that require action. We have, however, attempted to address the major overarching and far-reaching actions that are crucial to Kentucky's future.

We must remain open to the timely incorporation of future technologies as they emerge with exhibited capabilities of greater efficiency and environmental friendliness. For example, to combat the risks inherent in our increasing dependence on imported oil and the escalating costs associated with growing worldwide demand for all energy resources, the United States, including Kentucky, has available a potentially large alternative liquid fuels resource base in the forms of coal and biomass to substitute for conventional oil imports. The development of alternative fuels from our domestic resources can move us toward transportation fuel independence, while at the same time creating high-value jobs and reducing trade and budget deficits. Additionally, this strategy provides a long-term market for Kentucky coal.

Kentucky has been responding to its energy challenges in a number of ways. Within the past two years the Kentucky General Assembly enacted House Bill 299, House Bill 1 and House Bill 2. These bills established mechanisms to promote renewable energy projects and energy efficiency technologies within the state as well as development of alternative transportation fuels from our coal and biomass resources. See Appendix A for a detailed list of Kentucky legislation related to energy during the last decade.

> Coal is a low-cost, per BTU, mainstay of both the developed and developing world, and its use is projected to increase. Because of coal's high carbon content, increasing use will exacerbate the problem of climate change unless coal plants are deployed with very high efficiency and large scale CCS is implemented. CCS is the critical enabling technology because it allows significant reduction in carbon dioxide emissions while allowing coal to meet future energy needs.
>
> MIT, The Future of Coal

In 2007, Kentucky's General Assembly also took an important step in addressing issues of carbon dioxide unique to Kentucky. It directed a collaborative report on carbon management related to existing and new electricity-generating units, and provided funding for research on carbon capture and sequestration (CCS) from existing power plants; carbon storage in geologic formations; and enhanced oil and gas recovery through carbon dioxide injection. As a result of this funding, important industry-public sector-university collaborations have developed.

These significant pieces of legislation have established a foundation upon which to build an effective, comprehensive statewide energy strategy and have provided funding for the state to initiate key energy-related projects.

In June 2008, Governor Steve Beshear announced the state's partnership with the newly formed Western Kentucky Carbon Storage Foundation. With four key energy industry leaders -- Peabody Energy, ConocoPhillips, E.ON U.S. and TVA – and with the Kentucky Geological Survey, the Foundation will test a western Kentucky site for geological sequestration and help to advance the science and ultimate deployment of long-term carbon storage opportunities in the state.

Moreover, Kentucky's Public Services Commission (PSC) announced in October 2008 that it has encouraged the major investor-owned utilities to invest $7.8 million into established carbon capture and sequestration (CCS) research programs. The two research entities are the Carbon Management Research Group (CMRG), which is a partnership of the private sector and the University of Kentucky Center for Applied Energy Research (CAER); and the Kentucky Consortium for Carbon Storage (KCCS), which was created by the Kentucky Geological Survey and the Kentucky Department for Energy Development and Independence. KCCS is conducting the test of underground carbon storage in western Kentucky.

According to the World Resources Institute (WRI), "Interest in CCS has grown in recent years since it would significantly reduce emissions from fossil fuels, which are expected to continue to meet the world's energy needs for decades to come, due to their widespread availability and low cost. Challenging economic, technical, social, and institutional hurdles remain, however, before CCS can contribute significantly to a larger climate solution" (WRI, 2007). Among these challenges are legal and regulatory issues associated with CCS.

Thus, Kentucky's challenge is also a challenge at the national and international level. While we must diversify our energy mix, we must also find ways to utilize our coal resources in a carbon-constrained world.

Clean coal technology and technology to capture and sequester carbon dioxide are crucial to Kentucky's continued use of our coal resources; however, considerable development and demonstration work remains to be completed to ensure economically viable systems can be installed at the scale needed.

Many state and regional initiatives across the country are helping to frame the debate on climate change and determine the policy outcome regarding GHG emissions. In fact, in the United States, most of the actions toward addressing climate change are taking place at the state and regional level. Kentucky is a participant in many of these regional activities, and has recently joined the Climate Registry, a nonprofit organization governed by a board of directors of state, tribal, and provincial representatives that provides a mechanism to measure GHG emissions across industry sectors and borders.

Clean coal technology and technology to capture and sequester carbon dioxide are crucial to Kentucky's continued use of our coal resources; however, considerable development and demonstration work remains to be completed to ensure economically viable systems can be installed at the scale needed.

"Non-Renewables" Dominate Kentucky's Energy Production and Use Today

World events, climate change, uncertain supplies, and an ever-growing global demand for fossil fuels have converged to place our collective energy future in jeopardy. We can no longer count on a limitless supply of inexpensive fossil fuel to meet our future energy needs. Before discussing the energy plan's seven strategies and how they can guide us in the following decades, an overview of Kentucky's current production and use is provided on the next page.

Today, coal, natural gas, and petroleum account for 97 percent of Kentucky's total energy consumption. (See Figure 1.) The other three percent of the energy consumed in Kentucky comes primarily from hydroelectric and other renewable sources.

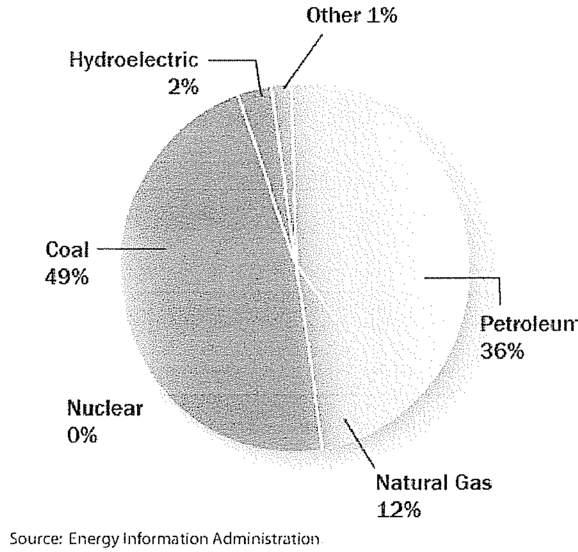


Figure 1: Kentucky's Energy Consumption by Source-2005

Petroleum

Kentucky receives petroleum products by pipeline and river barge. The state's total petroleum consumption is high (133,524 thousand barrels per year in 2005) relative to its population. Until October 2008, *diesel prices increased almost 70 percent* ($2.72 to $4.61 per gallon) in the last year; gasoline prices increased over 31 percent ($3.08 to $4.04 per gallon) in the same period. Petroleum prices decreased toward the end of 2008 as a result of decreased worldwide demand due to the economic downturn.

Natural Gas

Kentucky's natural gas production, most of which comes from the Big Sandy field in Eastern Kentucky, typically accounts for less than one percent of total annual U.S. natural gas production. The majority of Kentucky's natural gas demand is supplied by pipelines from the Gulf Coast. Industry is Kentucky's largest natural gas-consuming sector, accounting for about one-half of total natural gas consumption. More than two-fifths of Kentucky households use natural gas for home heating.

Natural gas prices have increased over 13 percent ($10.71 to $12.13 per thousand cubic feet) in the last year.

Coal

As noted previously, Kentucky is the third largest coal-producing state. It accounts for roughly one-tenth of all U.S. coal production and nearly one-fourth of U.S. coal production east of the Mississippi River. In addition, almost one-third of all the coal mines in the country are found in Kentucky, more than in any other state. With both surface and underground coal mines, large volumes of coal move in and *out of Kentucky by railcar and river barge* to more than two dozen states, most of which are on the East Coast and in the Midwest. In Kentucky, about three-fifths

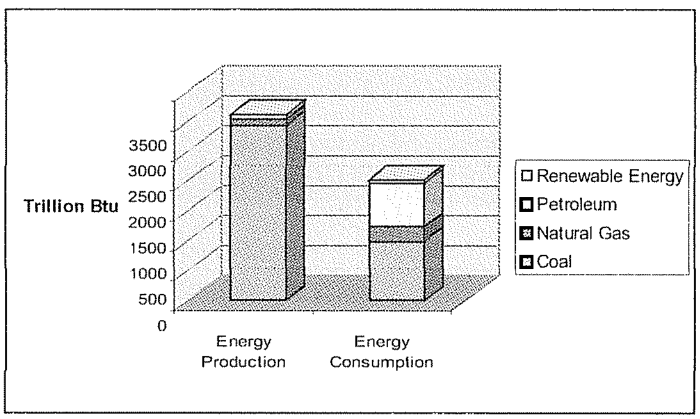


Figure 2: Comparison of Kentucky's Energy Production and Energy Consumption in 2005 by Source (all sectors)

of the coal supply is used for electricity generation, and most of the remainder is used in industrial plants. Kentucky exports nearly two-thirds of its coal mined each year to other states. (See Figure 2.)

Coal-fired power plants typically account for more than 90 percent of the electricity produced within Kentucky, making it one of the most coal-dependent states in the nation.

The price of Central Appalachia coal has doubled ($57.70 to $117.60 per ton) in the last year. Electricity prices, although increasing, have not yet begun to reflect this price run-up. If coal prices remain at these high levels, electricity prices will also spike.

Several hydroelectric power plants account for most of the state's remaining electricity generation. Kentucky is currently the fifth largest hydroelectric power producing state east of the Mississippi River.

Coal-fired power plants typically account for more than 90 percent of the electricity produced within Kentucky, making it one of the most coal-dependent states in the nation.

Kentucky Envisions the Future

The commonwealth already enjoys many comparative advantages in energy production, including a strong natural resource base, a highly skilled workforce with a strong work ethic, a highly qualified community of educators and researchers, and the commitment of its state government and legislature to achieve energy independence and reduce its carbon footprint. Building on these advantages, while encouraging innovation and ingenuity, will help Kentucky move forward to a secure energy future.

Responding effectively to the world's new energy realities is one of our most urgent and important challenges. We must identify and pursue aggressive, yet achievable, solutions to meet our energy needs. The following seven strategies presented in this action plan will make Kentucky a leader in the nation's efforts to attain energy independence and will provide environmental and economic benefits to the citizens of the state.

1. Improve the energy efficiency of Kentucky's homes, buildings, industries and transportation fleet.
2. *Increase Kentucky's use of renewable energy.*
3. Sustainably grow Kentucky's production of biofuels.
4. Develop a Coal-to-Liquids (CTL) industry in Kentucky to replace petroleum-based liquids.
5. Implement a major and comprehensive effort to increase gas supplies, including coal-to-gas in Kentucky.
6. Initiate aggressive carbon capture/sequestration projects for coal-generated electricity in Kentucky.
7. Examine the use of nuclear power for electricity generation in Kentucky.

We shall become an energy producing state for our nation while at the same time achieving efficiency in our personal energy use. This will lead us to a position of leadership in the United States and to strong economic development, as we mitigate GHG emissions, and provide revolutionary positive changes in Kentucky by 2025.

Kentucky Must Act Now

Kentucky's energy use is projected to grow by slightly more than 40 percent between now and 2025 under a Business-As-Usual scenario. This energy growth encompasses all sectors, including electricity generation, natural gas use, and transportation fuels. Reliable estimates show an annual growth in electricity generation alone of close to two percent. As noted, between now and 2025, according to estimates from the Kentucky Public Service Commission, Kentucky will need an additional 7,000 megawatts of electricity generation. The anticipated additional generation does not even account for the retirement of existing coal-fired plants, whose average age in Kentucky is already more than 35 years.

This plan, *Intelligent Energy Choices for Kentucky's Future*, will substantially reduce energy demand *such that per capita energy use in Kentucky will remain at current levels.*

Implementing these strategies will also lead to a much more diversified energy portfolio for the commonwealth, while we expand economic development opportunities in all energy sectors. Figure 3a shows the current energy utilization, what it will look like in the BAU scenario, and how this plan will provide a much more flexible and effective energy portfolio. Diversifying Kentucky's energy portfolio provides enormous economic, environmental and energy security benefits, and will be key to the state's prosperity in the future. If we rely on the same model we have today, we will be increasingly vulnerable to these threats and our citizens, businesses, and industries will all be negatively affected.

For example, today, we rely on coal for more than 90 percent of our electricity. Our industrial sector has flourished as a result of low-priced coal-fired generation. In the future, primarily relying on one source of power for electricity

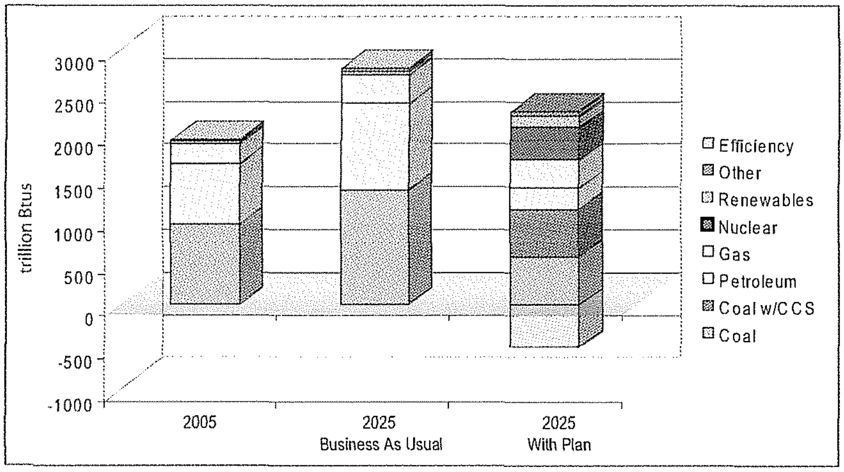


Figure 3a: Kentucky's Total Energy Use

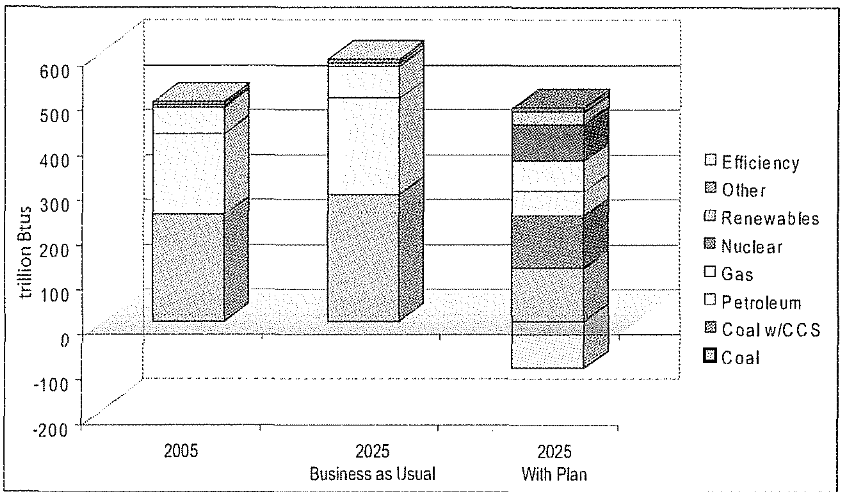


Figure 3b: Kentucky's Per Capita Energy Use

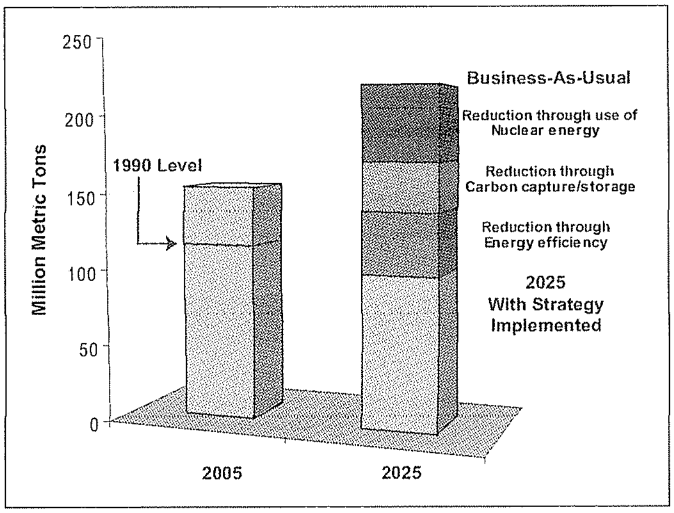


Figure 4: Reductions In Carbon Dioxide Emissions

generation will not be prudent in the face of imminent climate change legislation at the federal level. While we anticipate retrofits of existing power plants for carbon dioxide capture, we must diversify our electricity generation to include renewables and other sources such as nuclear power.

At the same time, relying on coal-fired power generation in the state will not be sufficient to support Kentucky's coal industry. If other states cease purchase of Kentucky coal, our coal industry and the resulting severance taxes will be diminished considerably. By moving some of our coal production into transportation fuels and synthetic natural gas, we support our efforts to become less vulnerable to imports and ensure a continued market for Kentucky coal, sustaining the 17,000 plus jobs in the coal industry, as well as the industry's other effects.

We cannot predict with certainty the technological advances that will occur over the next two decades, but we can develop flexibility in our energy portfolio that enables us to take timely advantage of those advances. For example, if cellulosic biofuels develop rapidly, we will have in place the basic industry to readily adapt to these technological advances. If much more efficient and economical solar or wind technologies are developed, we will be able to exploit those without delay. If nuclear power takes hold more rapidly at the national level, which indications are it will, our utilities could already be moving in that direction. A diverse portfolio gives us the flexibility to effectively utilize lower carbon-emitting technologies and fundamentally much more environmentally benign energy solutions.

Just as we will experience growth in our demand for energy, our GHG emissions will continue to escalate under a Business-As-Usual scenario. With such a high reliance on fossil fuels, our projected GHG emissions will be more than 40 percent higher than they are today if we do not take action (See Figure 4). With implementation of these proposed strategies, however, our GHG emissions could be more than 50 percent lower in 2025 than they would otherwise be. More significantly, if we implement the strategies presented in this plan, GHG emissions in Kentucky could actually be 20 percent lower in 2025 than our 1990 emissions.

A Renewable and Efficiency Portfolio Standard Will Be Established

We must launch our efforts by first focusing on improving energy efficiency in all sectors of Kentucky's economy and adopting practical cost-effective conservation practices. Initiatives to improve energy efficiency have little cost compared with the economic and environmental benefits to be gained. A Renewable and Efficiency Portfolio Standard (REPS) is proposed whereby 25 percent of Kentucky's energy needs in 2025 will be met by reductions through energy efficiency and conservation and through use of renewable resources. Energy efficiency alone will offset at least 18 percent of Kentucky's projected 2025 energy demand. This would allow us to meet 60 percent of our projected 2025 energy requirements through energy efficiency, before any new generation.

As part of the REPS, we will also significantly increase utilization of renewable energy resources within the commonwealth. Today, renewable energy accounts for only about three percent of Kentucky's entire energy portfolio (this includes biofuels such as ethanol and biodiesel and renewable energy used to generate electricity). We will develop our renewable energy resources by encouraging greater generation of electricity from such sources as wind, hydro, and solar, and by providing incentives for biomass production. Through the REPS, we will increase Kentucky's renewable resources to more than triple our current use by 2025. We will achieve this growth by relying on our domestic renewable resources, thereby growing jobs both within the "green collar" manufacturing sector and within our home-based agricultural sector

Strategy 1 of this plan details how and what is required for us to achieve a reduction of 18 percent in our projected energy needs by 2025. These actions target energy efficiency and conservation in homes, offices, government buildings, industries, and the transportation sector. As an integral part of the proposed REPS, *Strategy 1*, with its emphasis on energy efficiency and conservation, will be one of the key components of the state's actions to reduce greenhouse gases. See Figure 4, which illustrates the 39 million metric tons of reduced GHG emissions that will result from implementation of this strategy.

Strategy 2 strengthens the greenhouse gas reduction efforts, and is another element of the REPS. By targeting to the fullest extent development of Kentucky's renewable resources, including solar, wind, hydro, and biomass, Kentucky's energy portfolio will begin to take on more breadth and offer new economic and environmental opportunities.

The proposed REPS is designed to allow the commonwealth the opportunity to maximize our renewable energy resources within the state without forcing our utilities to purchase higher-priced out-of-state renewable energy. But even with this aggressive REPS, Kentucky will still need to look at our traditional energy source – coal – and other options such as nuclear.

An Alternative Transportation Fuels Standard Will Be Established

To transition away from dependence on foreign petroleum, Kentucky and the nation can turn to domestic resources. By implementing the strategies presented in this plan, Kentucky can displace 60 percent of its reliance on foreign petroleum by utilizing fuels derived from biomass and coal, and by plug-in hybrid vehicles. We can do this using existing infrastructure in such a way that we do not increase our net carbon dioxide emissions. As we have witnessed dramatic fluctuations in the price of oil during 2008, we should be reminded of our economic and energy security vulnerability that results from our growing dependence on imported oil. Our businesses, citizens, and government agencies cannot even plan adequate budgets in the face of such uncertainty over prices. The fact that lower prices in the latter part of 2008 were a reflection of worldwide recession should not bring a sense of relief.

In *Strategy 3*, which will be included in the REPS and the ATFS, we will develop Kentucky's biomass *resources in a sustainable, environmentally sound and economically beneficial manner. While building* on the state's successes with corn-based ethanol production and soy-based biodiesel, the state will be positioned to take advantage of existing technologies that expand our options for producing environmentally friendly bio-based fuels from cellulosic biomass.

Even with aggressive energy efficiency and renewable energy efforts, the commonwealth will need other resources to meet growing energy demand. If we hope to reduce our dependence on foreign oil, we must turn to our domestic fossil fuel resources, especially our coal resources, by deploying advanced cleaner coal technologies. The reduction in carbon dioxide emissions by 2025, can occur despite the fact that we continue to utilize our coal resources (see Figure 4). We can do this by capturing and storing carbon dioxide emissions from existing coal-fired electric generating units and from newly developed coal-conversion industries that help meet our domestic transportation fuel and natural gas needs.

As another component of the ATFS, *Strategy 4* further develops the goals and objectives to establish a vibrant coal-derived liquid transportation fuels industry. These objectives have been clearly articulated by Kentucky's elected officials, and the action items in *Strategy 4* will help to ensure this industry has a viable future in the commonwealth. The resulting energy security and economic development opportunities are significant, and the coal-to-liquids industry will be key to the continued employment of coal miners within the commonwealth.

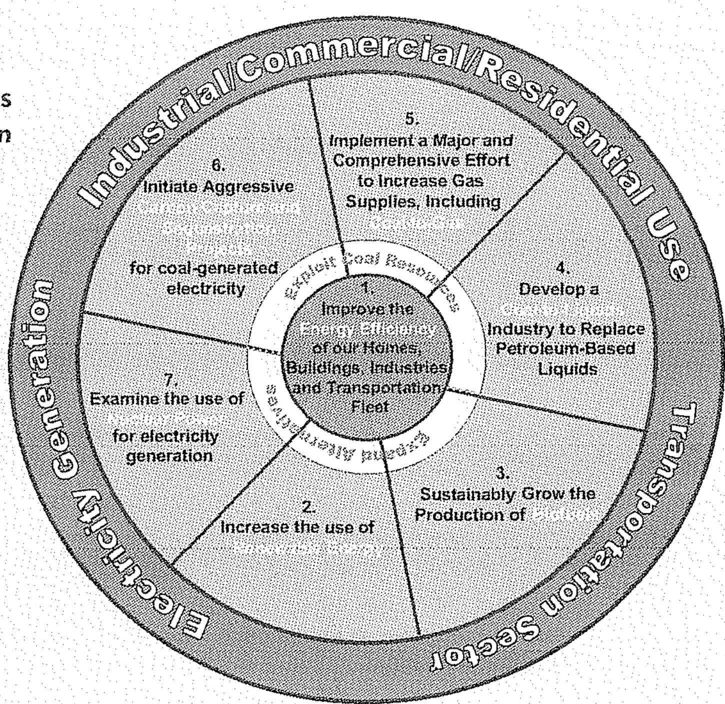
Kentucky Will Rely on New, Cleaner Technologies at Home

Equally important as weaning ourselves from imports of foreign oil is reducing our dependence on imported natural gas. *Strategy 5* establishes an action plan directed toward increased natural gas production in the commonwealth and production of synthetic natural gas from Kentucky's coal resources. Again, this initiative intends to build upon the intent of policymakers within Kentucky in recent years to promote coal-conversion technologies that supply Kentucky with liquid transportation fuels and synthetic natural gas.

For Kentucky to achieve its greenhouse gas reduction goals, deployment of carbon dioxide capture and storage technologies on a large scale is crucial. Kentucky must find ways to reduce carbon dioxide emissions while ensuring that we meet our growing energy needs. The action plan in *Strategy 6* will help Kentucky initiate aggressive carbon capture and storage projects, with a goal by 2025 that 50 percent of Kentucky's coal-based energy facilities will be equipped with carbon management technologies. These reductions, illustrated in Figure 4, also show how a combination of actions and technologies will be necessary to achieve carbon dioxide emissions reductions.

Another key component to reducing Kentucky's carbon dioxide emissions is deploying non-carbon dioxide emitting technologies to meet our baseload electricity generation needs in the future. One option that must be considered is nuclear power. Given the lengthy timeframe for planning and construction of nuclear power plants, it is prudent for Kentucky's citizens and policymakers to launch a serious discussion today of how we should pursue nuclear power. The uncertainty surrounding federal climate legislation, the feasibility of deploying large-scale CCS within the next couple of decades, and Kentucky's and the nation's growing demand for electricity require that we consider seriously our options regarding nuclear power. Figure 4 illustrates the carbon dioxide reductions that would result from effective utilization of nuclear power in Kentucky—approximately 30 percent of Kentucky's estimated demand can be met through nuclear generation by 2030.

The diagram to the right depicts the seven strategies encompassed in this comprehensive plan that addresses issues related to all energy sectors in Kentucky.



Underlying Goals:

- Energy Security
  - We will have stable, predictable energy costs and reliable energy supply
  - We will lead the way for coal 's future to reduce U.S. dependence on foreign oil
- Economic Prosperity
  - Reliable and stably priced energy will provide a *competitive advantage for* economic development
  - Energy systems will be technology driven
- Environmental Sustainability
  - We are committed to reducing green house gases
  - *We will* maximize the benefits of our reduced carbon emissions
  - We will be viewed as an environmentally conscientious state

Strategy 1:

Improve the Energy Efficiency of Kentucky's Homes, Buildings, Industries and Transportation Fleet

GOAL **Energy efficiency will offset at least 18 percent of Kentucky's projected 2025 energy demand.**

Strategy 1 encompasses elements of Kentucky's proposed Renewable and Efficiency Portfolio Standard (REPS) and the Alternative Transportation Fuels Standard (ATFS).

The REPS states that "by 2025, Kentucky will derive at least 25 percent of its projected energy demand from energy efficiency, renewable energy and biofuels while continuing to produce safe, affordable and abundant food, feed and fiber."

The ATFS states that "by 2025, Kentucky can displace 60 percent of its reliance on foreign petroleum by utilizing fuels such as those derived from biomass and coal, plug-in hybrid vehicles, and compressed natural gas."

INTRODUCTION

Both nationally and worldwide, we are experiencing dramatic increases in costs for our traditional sources of energy – coal, natural gas and petroleum. Supply and demand are seeking new balance points at much higher price levels with devastating impacts in many regions of the world. In the United States, including Kentucky, the rates charged by electric utilities are increasing as a result of rising prices for coal and natural gas used to generate power.

Prices for coal, natural gas, and petroleum likely will continue to increase, and therefore consumers' energy bills will continue to rise. Most would agree that the era of cheap energy is over. The choice we face is to take no action and see large price increases, or to take prudent actions now and see smaller price increases. In the near term, energy efficiency and conservation represent the fastest, cleanest, most cost-effective, and most secure methods we have to reduce our growing demand for energy and to help us address issues surrounding global climate change.

Nationally, approximately 25 percent of total electricity usage can be saved cost-effectively, at an average cost of three cents or less per saved kilowatt-hour. New generation sources cost five cents or more per kilowatt-hour, making efficiency the lowest cost electricity resource (Laitner, 2007). A recent analysis conducted by La Capra Associates shows that Kentucky's marginal cost of electricity could increase by 15 to 65 percent with the implementation of federal climate change and greenhouse gas policies. Such increases further underscore the value of energy efficiency (Smith, 2007).

Although the terms energy efficiency and energy conservation are often used interchangeably, the two can have different meanings. Energy conservation typically refers to reducing the services energy provides from the levels that would normally be used. For instance, if you raise your

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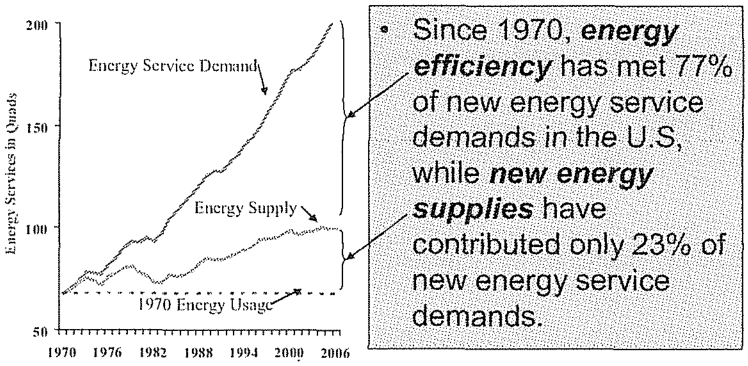


(Ehrhardt-Martinez, 2008)

Figure 5: Contributions from Energy Efficiency Outstrip Contributions from New Supplies: 1970-2006

home's thermostat from 70 degrees to 74 degrees during the summer cooling season, then you are practicing energy conservation. On the other hand, if you replace an incandescent light bulb with a compact fluorescent bulb, you are increasing your energy efficiency.

Both energy conservation and energy efficiency concepts may also be placed into the broader context of "energy demand management." In a utility regulatory context, an example of a demand management program that is neither conservation nor energy efficiency would be a load shifting program. From the utility's point of view, having people change their consumption from peak times of day to off-peak times may allow the utility to avoid turning on a natural gas-fired generating peaking unit, which costs more to operate than a typical base load coal-fired generating unit. Such actions will save money since the higher cost unit is not being used.

Again using energy efficiency as an expression for all types of energy demand management programs, many studies have concluded that it has a key role in meeting our future energy demand. Stated conversely, energy efficiency can be thought of as an important source of incremental energy supply to help meet future energy needs.

According to the American Council for an Energy Efficient Economy (ACEEE), since 1970 energy efficiency has contributed more than three times as much energy to the U.S. economy as new supplies have contributed. In other

ENERGY STAR Schools in Kentucky

Kentucky is proving that energy-efficient schools make a difference by building schools that qualify for the ENERGY STAR label. Schools that earn the ENERGY STAR label use less energy, cost less to operate, lighten the load on the environment and improve the comfort and indoor air quality for building occupants. Kentucky has 34 buildings that have received the ENERGY STAR label, with 15 of those being public K-12 schools. These schools are some of the most energy-efficient facilities in the commonwealth. On average, these schools use as much as 33 percent less energy than a traditionally built school, and can save $45,000 to $50,000 in annual energy costs. ENERGY STAR is a joint program of the U.S. Environmental Protection Agency and the U.S. Department of Energy that helps save money and protect the environment through superior energy efficiency.

words, since 1970, based on projections of historical energy consumption increases, we would have had to build/discover and bring to market four times as much "new supply" of energy as we actually delivered to the market (Ehrhardt-Martinez, 2008).

Not only does energy efficiency result in savings today, the savings are compounded over time as energy prices continue to rise. Dollar for dollar, energy efficiency is one of the best energy investments Kentucky can make.

Energy efficiency can also provide significant benefits to the state and national economy. Energy efficiency improves business competitiveness, household savings and the environment. Green jobs, sometimes called green collar jobs, that result from investments in energy efficiency and renewable energy, can create opportunities for the economy as well. While additional Kentucky-specific research is necessary to estimate the job impact attributable to increased levels of energy efficiency or use of renewable energy sources, there are numerous studies that provide information on a national scale.

For example, a November 2007 study by the American Solar Energy Society showed that renewable energy and energy efficiency industries today generate nearly $1 trillion in revenue in the United States and contribute more than $150 billion in tax revenue at the federal, state and local levels (Bezdek, 2007).

The National Action Plan for Energy Efficiency (NAPEE), a national commitment to energy efficiency by more than 50 leading U.S. gas and electric utilities, utility regulators, and partner organizations, estimates that if utilities were to invest roughly $7 billion a year in energy efficiency, this would leverage *another $20 to $30 million in non-utility investment, yielding annual savings to consumers* of some $22 billion by 2017. These investment levels could result in the creation of nearly 300,000 jobs annually (Song, 2007).

Kentucky's investment in energy efficiency will not only reduce our emissions of greenhouse gases and dependency on oil from foreign sources but will serve to stimulate economic growth and new job creation. *Thoughtful policies that encourage Kentuckians to* consider and implement cost-effective energy efficiency measures will help Kentucky's economic outlook.

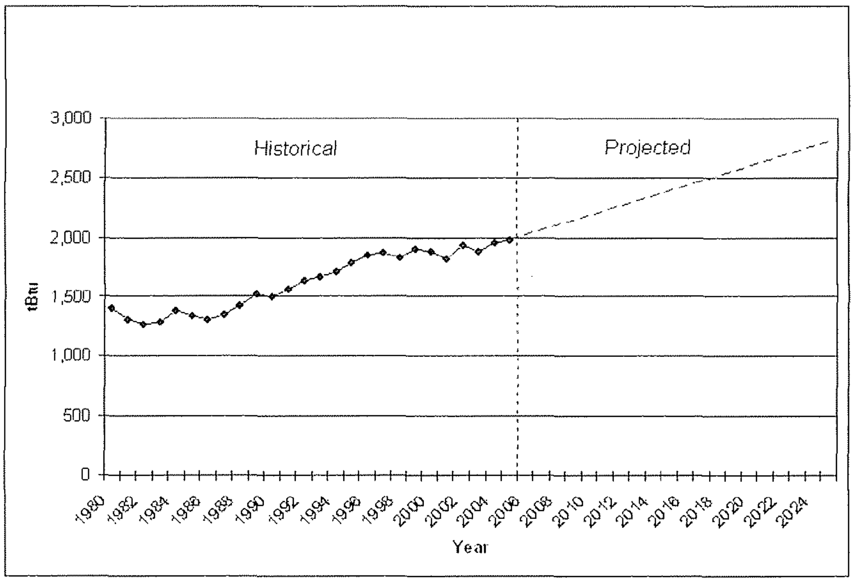


Figure 6: Total Energy Consumption 1980-2005, Projected to 2025 (EIA, 2005b)

Kentucky's Current and Projected Energy Use Patterns

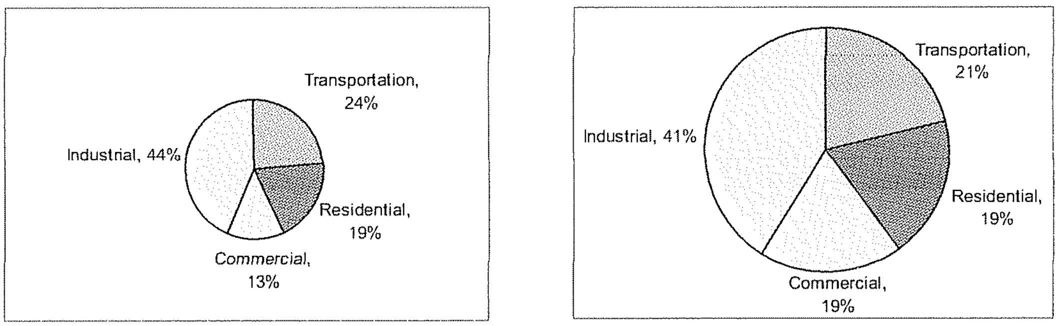
With our electricity rates among the lowest in the United States, it is not surprising that Kentucky's per capita consumption of residential electricity is among the highest in the country. Our low rates have tended to be a barrier to the adoption of effective energy efficiency practices in the state.

In 2005, total energy usage in Kentucky was the sixth highest per capita in the United States (EIA, 2005a). In the same year, the average expenditure per Kentuckian on energy was $4,084, ranking the state ninth nationwide even though we ranked 45th nationwide in energy prices (dollars per million Btu). This discrepancy underscores the fact that Kentucky is an energy-intensive state on a per capita basis. In 2006, Kentucky's electrical use per industrial customer was 427 percent above the national average (ranking third highest); residential use per customer was 24 percent above the national average (sixth highest). These averages indicate that there is opportunity for energy efficiency in Kentucky.

Energy consumption in Kentucky has increased dramatically since 1980, and the trend toward *increased consumption is expected to continue.*

2005 Source Energy Usage in KY
(Total = 1970 tBtu/yr)

2025 Projected Source Energy Usage in KY*
(Total = 2815 tBtu/yr)



* Business As Usual – BAU projections assume energy efficiency and energy conservation continue at current levels but no new efficiencies or conservation initiatives are introduced.

Figure 7: 2005 Source Energy Usage in Kentucky and Projected to 2025

Table 1: Percent Increase from 2005 to 2025 of Source Energy Used

Source Energy Used in 2005 And Projected Use in 2025 (tBtu)			Percent Increase
Year	**2005**	**2025**	
Residential	370	536	45
Commercial	260	527	103
Industrial	863	1147	33
Transportation	477	605	27
TOTAL	1970	2815	43

(Colliver et al., 2008)

The EIA Annual Energy Outlook (AEO) gives projections for annual energy consumption through 2030 for the East South Central region of the United States. In order to use the AEO as the basis for the state's projected usage, Kentucky's fraction of the existing East South Central region usage was assumed to continue into the future (Colliver et al., 2008). The EIA updates its energy forecast on an annual basis; rather than continuously track the most recent forecast the AEO 2006 was used as the reference case.

"Source energy" is the energy content of the primary fuel and is a measure of energy before electric transmission and generation losses. Between 2005 and 2025 Kentucky's total source energy usage is projected to grow from 1,970 trillion Btu per year to 2,815 trillion Btu per year, an increase of over 43 percent, approximately 1.8 percent each year for the 20-year period in a business-as-usual scenario (see Figure 7). The commercial and residential sectors are predicted to experience the largest percentage growth in energy usage (Table 1) (Colliver et al., 2008).

Toyota is committed to the continuous improvement of energy performance by having systems in place to identify opportunities for energy savings. The company accomplishes this through their successful plant-wide energy assessments to find energy reduction opportunities. These assessments have allowed Toyota to continually improve their energy performance. Within the span of one year alone, 2005, Toyota decreased energy intensity eight percent while increasing production four percent (EPA, 2008a).

Conservation and Energy Efficiency in Context

With cost-effective programs in place, conservation and energy efficiency are projected to be the largest contributors to meeting our growing energy demand in 2025. Figure 8 shows that energy efficiency could offset up to 18 percent of our total energy, or 511 trillion Btu, in 2025. Stated another way, about 60 percent of our new energy requirements could be satisfied with energy efficiency, not new production. This is not unrealistic as the United States has met 77 percent of its new energy demands with energy efficiency since 1970 (Laitner, 2007).

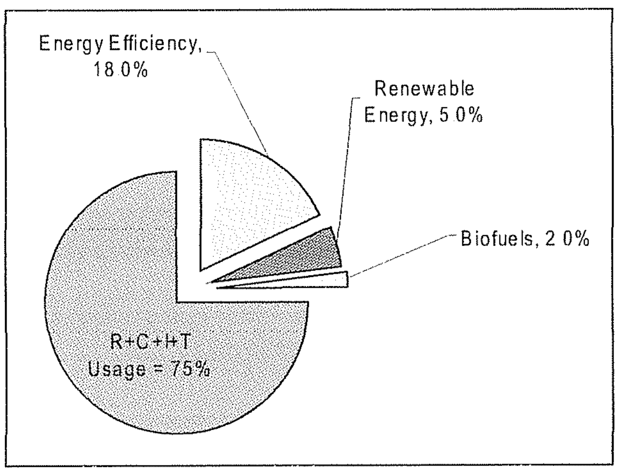


Figure 8: Projected Contribution of Energy Efficiency, Renewable Energy and Biofuels to meet Kentucky's Total 2025 Energy Demand (Total Demand=2815 tBtu)

Using an analysis by the University of Kentucky as a basis, energy efficiency in the residential, commercial and transportation sectors could offset about 10 percent of our projected 2025 energy demand; renewables five percent (*Strategy* 2); and biofuels another two percent (*Strategy* 3) (Colliver et al., 2008). The remaining eight percent in *Strategy 1* includes industrial, transportation and energy efficiency technologies not addressed in the University of Kentucky analysis. Additional analysis is needed to determine the total energy efficiency potential for the industrial sector in Kentucky.

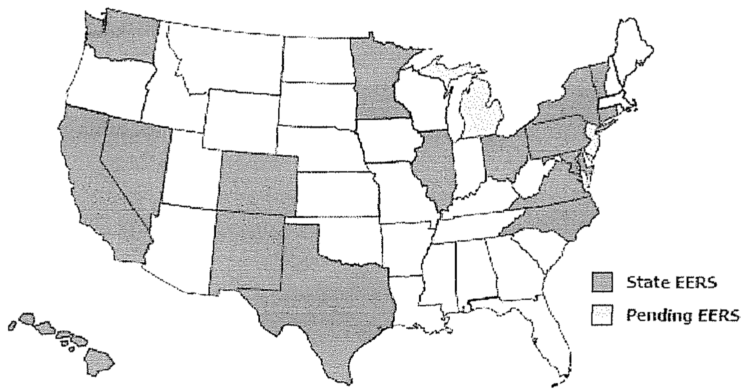
The identification and implementation of energy efficiency programs is a dynamic process. Rising energy prices and technological advances significantly affect the cost-effectiveness of energy-efficiency programs. Industry and business must continuously reassess these variables along with business trends to find optimum energy efficiency solutions that help reduce operating costs.

Opportunities to Reduce Energy Consumption

Energy Efficiency Resource Standards

A growing number of states are adopting energy efficiency resource standards (EERS) or energy efficiency portfolio standards (EEPS), to help ensure that cost-effective energy efficiency measures for electricity and natural gas are being implemented.

Currently, 17 states have goals using EERS that quantify how much energy savings will be generated from energy efficiency measures. EERS consist of electric or natural gas energy-savings targets for utilities, often with flexibility to achieve the target through a market-based trading system. EERS encompass end-user energy-saving improvements that can include distribution system efficiency improvements, combined heat and power (CHP) systems, and other high-efficiency distributed generation systems (Nadel, 2006). In Kentucky, the Tennessee Valley Authority (TVA) established a voluntary energy efficiency target to reduce future systemwide demand by 1,200 megawatts by 2013 (EPA, 2008b) (Figure 9).



Notes: New Jersey and Michigan have pending EERS requirements
(ACEEE, 2008)

Figure 9: State Energy Efficiency Resource Standard (EERS) Activity, May 2008

EERS require that energy providers meet a specific portion of their electricity and natural gas demand through energy efficiency. EERS are intended to help overcome the various barriers that keep utilities and other players from investing in cost-effective energy efficiency that several studies predict could meet up to 20 percent of the nation's energy demand, or about half of the expected demand growth (Nadel, 2004). However, in many states, market barriers, regulatory disincentives, or insufficient information about the benefits of energy efficiency keep utilities and other customers from investing in cost-effective energy efficiency to its full potential.

States have found that establishing explicit targets, based on sound analysis of technical and economic potential, can help reduce energy demand, cut emissions, help address concerns with system reliability and provide other energy-related benefits (EPA, 2006).

In some cases, states have combined EERS with *additional policy measures such as demand-side* management (DSM) programs, public benefit funds and different pricing structures that allow incentives for utilities to earn revenue in ways that are not entirely linked to additional sales. Aggressive EERS targets will require that all economic sectors be considered and addressed.

Under EERS, a state utility commission specifies numerical energy savings targets that natural gas and/or electricity service providers must meet, on an annual and sometimes cumulative basis. EERS can be set as a percentage of load growth or base year sales, or as a fixed number of units of energy savings (e.g., kilowatt-hour or Btu). Targets can also cover peak electricity demand (e.g., megawatts capacity). The appropriate EERS target depends upon a number of factors including the economically achievable energy efficiency potential, funding availability, emission reduction goals, and other issues including how to treat any existing energy efficiency requirements (EPA, 2006).

The implementation of an EERS occurs primarily through designated utilities. However, continued state involvement is important to oversee the development of implementation rules. In particular the state's role in evaluating measurement and verification (M&V) is critical to maintaining credibility for the market and commodity.

PUBLIC BENEFIT FUNDS

Establishing regulatory mechanisms and funding sources for utility programs to help achieve the efficiency resource goals is another key issue states have encountered. Different approaches have included one or more of the following: utilizing resources under a public benefit fund (PBF), allowing for cost recovery as part of utility rates, providing direct funding, and establishing regulatory provisions that allow new rate designs (EPA, 2006).

PBFs, also known as system benefits charges (SBCs), are typically created by levying a small charge on every customer's electricity and/or natural gas bill. These funds provide an annual revenue stream to fund energy efficiency programs. Currently, 30 states and Washington, D.C., provide nearly $3 billion annually for energy efficiency and related programs via this mechanism. States with restructured as well as traditional electricity markets are using PBFs as a component of their energy efficiency, renewable energy and low-income portfolios. In Kentucky a PBF of 1 mil per kilowatt-hour would generate approximately $67 million annually, based on 2006 retail sales of 66,886 thousand megawatt-hours by Kentucky's regulated investor-owned and cooperative utilities.

The development of both utility-sponsored and non-utility-sponsored programs should be considered when designing a plan to achieve the EERS. Utility-sponsored programs are traditional demand-side management programs using cost recovery while non-utility-sponsored programs are those funded through other mechanisms (e.g., PBF).

A challenge for Kentucky to implement an EERS will be to ensure that it is applied equitably across the commonwealth and that both jurisdictional and non-jurisdictional energy service providers and their customers are considered. How best to approach this challenge will require further analysis and discussion between stakeholders, legislators, regulators and executive agencies.

As energy efficiency programs designed to achieve the EERS increase in sophistication and complexity there will be a demand for improved energy management protocols and control systems. These new protocols and systems will come as improvements and upgrades are made in the energy transmission infrastructure. Several states are already upgrading their energy transmission infrastructures through the implementation of "smart grid" technologies. These are technologies that enable consumers to choose what type of energy they receive, as well as having the ability to manage their own consumption habits through in-home automation. Consumers better understand how energy is used within their home or business, how much usage costs them, and the impact that energy usage has on the environment (Xcel Energy, 2008).

A "smart grid" is essentially an electric system that integrates the infrastructure, processes, devices, information and market structure so that energy can be generated, distributed, and consumed more efficiently and cost effectively; thereby achieving a more resilient, secure, reliable and environmentally benign energy system. "Smart grid" builds on many of the technologies already used by electric utilities but adds communication and control capabilities that will optimize the operation of the entire electrical grid. It is also positioned to take advantage of new technologies, such as plug-in hybrid electric vehicles, various forms of distributed generation, solar energy, smart metering, lighting management systems and distribution automation (NEMA, 2008).

The development of a new technologically advanced electric network will require additional resources and funding that must be evaluated and balanced against enhanced capabilities, reliability and overall benefit to the utility and their customers.

Beyond the benefits tied to reduced energy use, states have found EERS have a number of particular advantages as a policy approach (EPA, 2006). The advantages include:

- Simplicity - EERS create a straightforward resource acquisition target for energy providers.
- Cost-Effectiveness - Setting an energy efficiency requirement without explicitly setting aside a pool of funds challenges electricity and natural gas providers to meet the goal in the most cost-efficient manner.
- Specificity - By articulating a specific numeric target, EERS can be effective in illuminating how much energy efficiency will contribute to reaching goals of energy demand reduction as well as emission reductions and other public policy goals.
- Economies of Scale - The macro-level targets inherent in EERS allow energy providers to aggregate savings across enough end-uses and sectors to meet the overall savings goals cost-effectively. This helps address a fundamental barrier to energy efficiency resource development: the distributed nature of energy efficiency resources. Securing substantial energy-efficiency gains in every end-use and use sector involves millions of homes, offices, factories, and other facilities and thus can be difficult when approached at a micro-level.
- Accountability - Because utilities will have an measurement and verification protocol to follow, reliable estimates of actual savings can be developed. This feedback can lead to ongoing modifications to energy efficiency programs to make them more effective.

There is little doubt that energy prices will continue to climb. Higher energy prices will certainly be followed by significantly higher energy bills, unless policies are put in place to reduce energy demand and usage. There will be a cost associated with implementation of an EERS program. However, there will also be a payback.

There is little doubt that energy prices will continue to climb. Higher energy prices will certainly be followed by significantly higher energy bills unless policies are put in place to reduce energy demand and usage. There will be a cost associated with implementation of an EERS program. However, there will also be a payback.

Energy Efficiency Education, Outreach and Marketing

Energy efficiency outreach and education are critical to help consumers learn about the benefits of energy efficiency and to provide information on the array of products and services available to them to help reduce energy consumption.

There are many readily available, easy to implement, cost-effective methods and products that Kentucky residents and businesses can use to save energy and lower expenses. Unfortunately, many people are unaware of these products and services, or they do not fully understand the benefits to be gained from them.

For example, for some measures that are not currently cost-effective or that are more expensive to purchase up-front, the federal government may offer incentives to help bring down the initial cost. Unfortunately, many consumers might not know these incentives exist. In some cases, certain energy efficiency measures are required by law, as in the case of the Kentucky Building Code (KBC) and the Kentucky Residential Code (KRC), which requires certain standards be incorporated into building practices. Still, many of these methods and products have not been widely adopted in Kentucky. Increasing public awareness of the need to strengthen energy provisions in the KBC and KRC, along with enhanced code enforcement, will improve the energy efficiency of Kentucky's buildings.

A multi-faceted and wide-ranging public information campaign would increase the knowledge of energy consumers and help them make better educated decisions about energy consumption and equipment purchases.

Energy Efficiency Leadership by State Government

State government can improve its building and vehicle energy efficiency and, at the same time, substantially cuts its costs. Activities already being initiated by the

Kentucky Energy Efficiency Program for Schools (KEEPS)

In partnership with the University of Louisville, the Energy and Environment Cabinet (EEC) supports the Kentucky Energy Efficiency Program for Schools (KEEPS), which helps participating schools and universities improve energy efficiency by offering tools, training and expertise. KEEPS allows participants to analyze and understand their energy consumption, which includes everything from lighting usage, heating and cooling issues to natural gas consumption. The 2008 Regular Session of the General Assembly passed HB 2, which requires that all 174 Kentucky public school districts enroll in the KEEPS program by January, 2010. Within the past two years, more than $160,000 in grant funding has gone to support KEEPS. An example of the program's effectiveness is Bullitt County school district, which joined KEEPS in 2006 as a pilot program. During the 2007-2008 school year, district electricity consumption was reduced by 11 percent (a savings of approximately $180,000) and natural gas usage was reduced by seven percent. The district's total avoided costs including account credits equaled nearly $246,000 for the 2007-2008 school year.

Finance and Administration Cabinet through the "Green Team" program must become more robust and must be adopted as the normal course of doing business. Additionally, as a large energy buyer, the state can boost the markets for advanced technologies and clean energy sources. The state should adopt and implement energy management practices and utilize renewable fuels and resources where doing so has a life-cycle cost benefit or can assist in transforming the market for these practices and technologies. See Near-Term Action 1 for details on state government actions.

Transportation Energy Efficiency

Transportation is closely tied to Kentucky's economy, security and health. High prices for fuel divert household dollars from other uses, traffic congestion erodes worker productivity, and prices climb for a broad range of consumer goods, including food. In the summer of 2008, crude oil prices set record highs.

One approach to reduce the cost, health and environmental impact of the transportation sector is to adopt technologies that make the vehicle-based transportation system more fuel efficient. Hybrid gasoline-electric vehicle (HEV) and plug-in hybrid electric (PHEV) technologies use less fuel per passenger-mile or ton-mile (freight), and alternative power sources at rest stops reduce the need for truck drivers to use fuel to idle their engines during overnight stays. Other transportation technologies help traffic flow more smoothly, enabling vehicles to use fuel only when necessary. All of these measures are in use and available in Kentucky, and they offer ways to reduce fuel costs and consumption. Technological advances in other transportation modes (e.g., rail and air) will also contribute to reduced fuel consumption.

"Smart" traffic control makes the flow of traffic more efficient through real-time monitoring, synchronized traffic devices and other technologies that reduce stopping and idling. These technologies include traffic cameras, sensors and controls that respond to traffic activity, and synchronized traffic signals or roadway configurations (roundabouts) that reduce idling (Georgia, 2006).

Efficient transportation technologies, such as fuel efficient vehicles, also significantly reduce the cost, health and environmental impact of the current transportation system. Transportation demand management (TDM) addresses the increasing demand for mobility by promoting alternatives to vehicle use, particularly single-occupancy vehicle use. Carpooling, vanpooling, telecommuting, public transit, walking and bicycling are TDM measures that promote conservation of transportation energy resources (Georgia, 2006).

In addition to these measures, the 2007 Energy Independence and Security Act will help Kentucky improve its overall vehicle fuel efficiency. The act requires the U.S. Department of Transportation to set tougher fuel economy standards, starting with model year 2011, until the standards achieve a combined average fuel economy for model year 2020 of at least 35 miles per gallon (MPG) (DOE, 2008).

ACHIEVING THE GOAL

Energy efficiency will offset at least 18 percent of Kentucky's projected 2025 energy demand.

Four action items have been identified to achieve this goal.

- An energy efficiency program for state government that has aggressive internal energy savings targets will be implemented. This program is important as it establishes a leadership role for state government.
- As part of an overall REPS, an Energy Efficiency Resource Standard (EERS) for electric and natural gas utilities will be set with a goal of reducing energy consumption by at least 16 percent below currently projected 2025 energy consumption. To achieve the EERS a combination of both utility-sponsored and non-utility-sponsored energy efficiency programs will be developed and implemented.
- Kentucky will have a strong education, outreach and marketing component that will support all of its other energy efficiency activities. Specific savings are not being attributed to this activity since it will support all of the efficiency and conservation efforts.
- Transportation energy efficiency programs and vehicle fuel economy initiatives will contribute at least another two percent representing a savings of approximately 500 million gallons of motor fuel annually. This percentage may be significantly large with efficiency improvements in air and rail transportation, and with greater adoption of plug-in hybrid vehicles and fuel-efficient diesel engine vehicles.

Near-Term Actions (1-3 years)

1. Kentucky will improve the energy efficiency of state-supported facilities and the fleet fuel efficiency of state-owned vehicles. State government will aggressively pursue achieving the requirements outlined in Sections 4-8, House Bill 2 and seek other opportunities that will reduce the energy consumed by all state-financed or state-owned buildings and vehicles.

   To measure progress toward improving energy efficiency in state government, the following targets are recommended:

   - By 2015, state-supported facilities will reduce energy consumption by 15 percent measured in energy per square foot per year using 2009 consumption as the baseline year. By 2025, state-supported facilities will reduce energy consumption by 25 percent as compared to the 2009 baseline year.
   - By 2015, the state vehicle fleet fuel economy measured in miles-per-gallon will improve by 30 percent, or by approximately five miles-per-gallon as compared to a 2007 baseline. By 2025, the state vehicle fleet fuel economy will improve by 50 percent as compared to the 2007 baseline.

   The Energy and Environment Cabinet (EEC) will have overall program responsibility to ensure that these goals are achieved and coordinated with state agencies, post-secondary schools and K-12 schools.

   The Finance and Administration Cabinet (FAC) will have a critical role in measuring and tracking progress, building and operating high performance facilities compliant with House Bill 2 standards, and procuring highly fuel-efficient vehicles for the state fleet. The High Performance Building Advisory Committee created in House Bill 2 will set aggressive building performance standards. The Kentucky Council on Post-Secondary Education, the Kentucky Department of Education and the Education Cabinet will also serve in support capacity to reduce energy usage in their respective school facilities.

The Judicial Branch will also implement actions that support the state energy goals for the facilities that they build, maintain or for which they pay energy costs.

The EEC in collaboration with state agencies, post-secondary schools and K-12 schools will develop a comprehensive energy management plan to achieve the state goals. The energy management plan will establish and support the following initiatives.

Buildings

- Establish an interagency energy management council consisting of representatives from all cabinet-level state agencies, the Kentucky Council on Post-Secondary Education and the Kentucky Department of Education to coordinate implementation of the plan. The EEC Secretary will chair the council.
- Leverage federal and state funding resources to support procurement of a computer-based energy management system that will allow FAC to track and measure energy consumption, develop benchmarks and evaluate progress in state-owned facilities.
- Require that all new state-funded buildings be commissioned, a quality assurance process that verifies and documents that a facility and all of its subsystems are operating as intended by the building owner and as designed by the building architects and engineers.
- *Strictly ensure that new building construction complies with whole building life-cycle cost analysis as prescribed by KRS 56.778.*
- Aggressively pursue the use of energy savings performance contracts (ESPC) as a financing mechanism for energy efficiency renovation projects. By January 2010, all state-owned buildings of 20,000 square feet or larger will be evaluated by the FAC to determine if they are viable candidates for ESPC. All viable candidates will be included in an ESPC by January 2012.
- Identify fiscal strategies that will allow capital construction budgets to be augmented by long-term energy efficiency savings from operational budgets.
- Establish a grants program for public K-12 school districts that will help offset the cost differential, if any, associated with designing and constructing a new or renovated school to ENERGY STAR or Leadership in Energy and Environmental Design (LEED) standards.

Procurement

- Establish minimum energy performance criteria for appliance and equipment purchases. ENERGY STAR appliances, lighting products and other products will be purchased when available.
- Develop purchasing criteria for the commonwealth to increase the overall fuel efficiency of the vehicles in its state fleet.

Vehicle Fleet

- Reduce the state fleet inventory to the minimum level feasible while still meeting agency travel needs.
- Downsize fleet vehicles to the smallest class possible while still meeting agency mission requirements. Purchase the most fuel-efficient vehicle having the best value within the class.

- Integrate cost-effective advanced technologies (e.g., Geographic Information System) into the management of Kentucky's vehicle fleet to reduce fuel consumption and improve overall asset control. The FAC should continue and expand current efforts to reduce fuel consumption of the state vehicle fleet.

2. Establish an Energy Efficiency Resource Standard (EERS) with the goal of reducing energy consumption by at least 16 percent below projected 2025 energy consumption.

   As components of the EERS:

   - Kentucky will implement recommendations from the House Bill 1, Section 50 report to authorize the Kentucky Public Service Commission (PSC) to develop model demand-side management programs and review, evaluate and approve DSM programs for regulated utilities. Developing and approving aggressive DSM programs will be the first step toward achieving the EERS goal. These recommendations include: amending the existing DSM statute (KRS 278.285) to broaden the PSC's authority to require utilities to implement specific DSM programs; clarify and standardize rules governing industrial customer exclusion from utility DSM programs; establishing standards for the evaluation of both proposed and ongoing DSM programs; and provide for additional PSC staffing and relevant training necessary to support increased activities associated with Integrated Resource Planning, DSM, Certificate of Public Convenience and Necessity, and other issues.

   - The EEC and PSC will conduct a study analyzing the energy efficiency potential of Kentucky's residential, commercial, industrial and transportation sectors.

   - The PSC and EEC will determine the impact, surcharge amount and cost of establishing a public benefit fund to support non-utility sponsored energy efficiency programs; education, outreach and marketing programs; and the renewable energy programs outlined in *Strategy 2*.

   - The EEC and PSC will conduct a study that analyzes how a PBF or EERS could be applied to both jurisdictional and non-jurisdictional energy service providers and their customers.

   - The PSC will conduct a proceeding to evaluate the impact and ramifications of setting an EERS goal of reducing energy consumption by at least 16 percent below projected 2025 energy consumption levels. The proceeding will address the following issues:

     – Identify the mix of programs that should be implemented to cost-effectively achieve the EERS by 2025.
     – Define a framework and specific tests for determining which efficiency programs and policies are cost-effective.
     – Develop and implement a plan for the recommended programs.
     – Estimate the cost to attain the energy consumption reduction goal.

   - The EEC will identify and recommend new tax incentives that will further enhance energy efficiency in the commonwealth.

3. The EEC, in conjunction with other state agencies and energy service providers, will conduct a vigorous and ongoing public energy efficiency awareness and education program.

   - The public awareness program will target both the general public and specific consuming sectors (agricultural, transportation, commercial, schools, etc.). The program will utilize partnerships, for instance with the state's universities and technical colleges and organizations such as, but not limited to, the Kentucky Cooperative Extension Service, the National Energy Education Development Project, Kentucky League of Cities, and the Kentucky Pollution Prevention Center, to increase outreach capabilities. It will aggressively market and promote the efficiency tax incentives in House Bill 2.

   - The EEC's development of a Kentucky public energy efficiency awareness and education program will include the following:

     – Form focus groups to assist in the development of survey design.
     – Determine baseline attitudes, practices and awareness of energy efficiency, conservation, use of renewable energy and biofuels through surveys.
     – Specify objectives and outcomes.
     – Develop the message, training outcomes and select media.
     – Implement the education, outreach and marketing program.
     – Assess results and make corrections to increase effectiveness.

   - The EEC will determine the benefits of establishing energy efficiency Centers of Excellence to deploy energy efficiency technology into all sectors of Kentucky's economy.

4. Kentucky will reduce continued reliance on imported oil by creating incentives that develop a robust plug-in hybrid electric vehicle and highly fuel-efficient vehicle market in Kentucky.

   - Support transportation demand management efforts that significantly reduce vehicle miles traveled (VMT) and utilize telecommunication technologies to reduce travel.

   - The EEC will identify and recommend incentives for plug-in hybrid electric vehicles and highly fuel-efficient vehicles in Kentucky to increase market share.

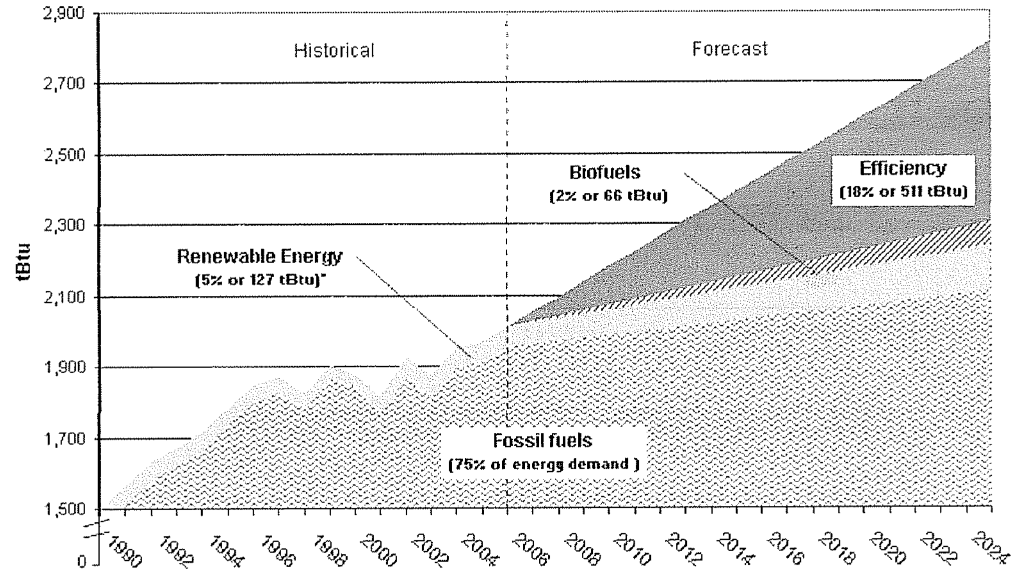
   - Implement "smart" traffic control and transportation demand management strategies through actions by the Kentucky Transportation Cabinet.

   - Develop and grow partnerships with utilities, universities and manufacturers that support an emerging highly-efficient vehicle industry in Kentucky.

   - The EEC will examine the impact of a vehicle carbon emissions standard and assessment for automobiles, SUV's and pick ups.

Mid-Term Actions (4-7 years)

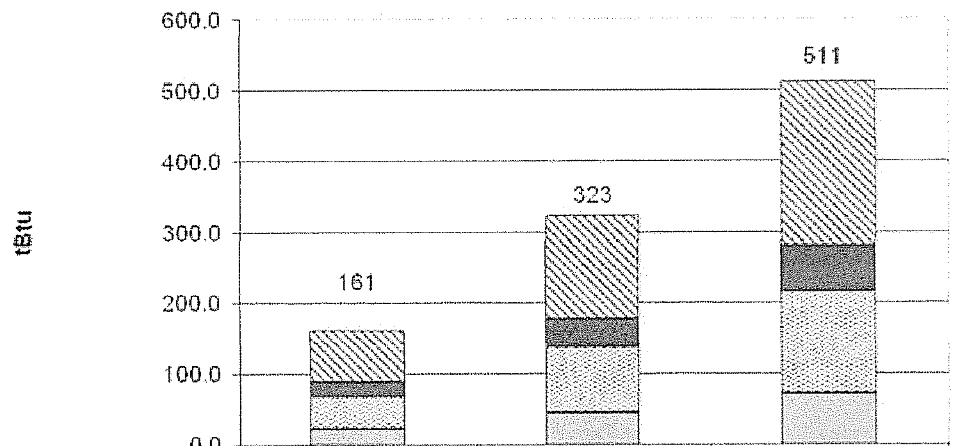
1. A policy for "smart grid" development will be established for Kentucky. Electric utilities must work in concert with the PSC to develop "smart grid" networks and technologies that will facilitate the next generation of DSM programs.



* Historical renewable energy was derived from hydroelectric (52-75%) and biomass (24-46%); remainder was unspecified "other."
(Source: EIA, http://www.eia.doe.gov/emeu/states/sep_use/total/use_tot_ky.html)

Figure 10: Kentucky Total Energy Consumption and Savings Potential (2025 Goal)

Energy Efficiency Targets 2012 - 2005 by Sector



Year	2012	2018	2025
Industrial/Other	73.4	146.8	232
Transportation	19.6	39.2	62
Commercial	46.1	92.2	146
Residential	22.3	44.7	70.7

Figure 11: Energy Efficiency Targets 2012-2025 by Sector

2. The PSC and EEC will evaluate rate design and ratemaking alternatives to enhance the impact of cost-effective energy efficiencies.

Long-Term Actions (>7 years)

1. Kentucky will continue to enhance its electric power system, from power generation to customer appliances, by integrating advanced "smart grid" technologies and communication systems to help Kentuckians better manage and control their energy demand and costs.
2. Kentucky will reevaluate the Energy Efficiency Resource Standard (EERS) goal of reducing source energy consumption by at least 16 percent below projected 2025 energy consumption to determine if additional reductions are achievable.

IMPLEMENTATION SCHEDULE

It is estimated that the energy efficiency measures outlined above can reduce Kentucky's projected "Business-As-Usual" (BAU) total source energy consumption in 2025 by at least 18 percent. Figures 10 and 11 identify *Strategy 1* targets for 2012 and 2018 as well. With energy efficiency targets, it is frequently difficult to determine the impact certain actions will have on the state's energy mix. The rate of adoption of energy efficient practices in the private sector will be greatly influenced by market prices. If energy prices continue to escalate at recent rates, adoption of energy efficient techniques and technologies will be greatly accelerated. If, on the other hand, energy prices were to decline sharply we would probably return to making decisions about energy based solely on energy price, and not on the true cost of energy, a cost that takes into account the very real impacts our energy consumption has long term on our environment, our economy and our national security.

Implementing energy efficiency is a dynamic and on-going process that changes with advances in technology and new economic markets.

In the near term, ensuring the PSC has adequate authority to spur expansion of DSM programs and providing authority for implementation of an EERS, along with implementation of effective public education and outreach initiatives, will help to accelerate early adoption of energy efficiency practices.

With those actions related to state government buildings and fleet vehicles, the state has direct control. Therefore, the targets established for state government will be more readily measurable. The High Performance Building Advisory Committee will recommend standards and regulations for high performance buildings pursuant to KRS 56.777. The FAC will promulgate regulations so that beginning July 1, 2009, all construction or renovation of public buildings for which 50 percent or more of the total capital cost is paid by the commonwealth will be designed and constructed, or renovated, to meet the high-performance building standards. Actions by the FAC and EEC to increase the fuel efficiency of the state's vehicle fleet will be put into action by October 2009.

By October 2009 the EEC will complete a plan designed to increase the market share of highly fuel-efficient vehicles in Kentucky using state incentives. This plan will be presented to the 2010 legislative session for consideration. Included in the plan will be recommended incentives designed to increase the market share of plug-in hybrid electric vehicles and highly fuel efficient vehicles in Kentucky.

The EEC will seek funding to conduct a study on the impact of establishing a vehicle carbon emissions standard and assessment for automobiles, SUV's and pick up trucks.

ENVIRONMENTAL BENEFITS & LIMITATIONS

The estimated 511 trillion Btu reduction in projected 2025 source energy consumption attributed to energy efficiency alone will result in a reduction of 39 million metric tons of carbon dioxide from the Business-As-Usual forecast, assuming there is no change in our energy portfolio mix from the present. This calculation is based on Kentucky's energy consumption profile as of 2005.

The environmental benefits of aggressively implementing cost-effective energy demand management programs are significant, though difficult to quantify. Cost-effective energy conservation programs have an immediate monetary effect by reducing energy related expenditures today. Taken together, energy efficiency programs will perpetuate the savings over time as long as people continue to conserve. While most cost-effective energy efficiency programs may require a greater up-front expenditure than conservation programs, they will result in ongoing savings with no further action required by the consumer.

To the extent that Kentucky's energy demand management programs are successful, the incremental insult we do to the environment is minimized. Also, when federal greenhouse gas mitigation legislation occurs, energy efficiency will benefit Kentuckians by helping to reduce the production of these gases.

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Strategy 2:

Increase Kentucky's Use of Renewable Energy

GOAL **Goal: By 2025, Kentucky's renewable energy generation will triple to provide the equivalent of 1,000 megawatts of clean energy while continuing to produce safe, abundant, and affordable food, feed and fiber.**

The goal for *Strategy 2* is part of Kentucky's Renewable Energy and Energy Efficiency Portfolio Standard (REPS) that states that "by 2025, Kentucky will derive at least 25 percent of its projected energy demand from energy efficiency, renewable energy and biofuels while continuing to produce safe, affordable and abundant food, feed and fiber."

INTRODUCTION

Energy from renewable resources benefits the environment while creating economic opportunities – the "green collar" jobs – for businesses, industry and rural communities. Renewable energy is one component of a three-part vision (*Strategies 1,2 and 3*) to provide 25 percent of Kentucky's energy needs by 2025 through energy efficiency, renewable energy and biofuels. To achieve this goal, the commonwealth must aggressively invest in the development of its renewable energy resources.

Renewable energy provides users, utilities, and communities many benefits beyond its direct energy services. These include:

- Distributed energy security – renewable energy systems operate on a smaller scale than centralized power plants and can be dispersed throughout transmission infrastructures.
- Energy independence – energy generated from renewable resources reduces the state's reliance on imported oil and natural gas.
- Improved environmental quality – relative to conventional power production, renewable energy systems reduce air pollutants, generate less thermal pollution and emit fewer greenhouse gases into the atmosphere.
- Economic investment – developing renewable energy markets diversifies local economies and creates employment opportunities for research, manufacturing and businesses.
- Job creation – growing the renewable energy sector will bring new technologies to market and create new "green collar" jobs.

Renewable energy refers to energy resources that are naturally replenishing and virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time (EIA, 2008). Examples of renewable energy resources in Kentucky include hydroelectric, landfill gas, biomass, solar and wind energy. For discussion in this strategy, renewable energy does not include biofuels derived from plant materials, which are discussed separately in *Strategy* 3.

Kentucky's Renewable Energy Today

Kentucky's current use of renewable energy resources is limited. According to the EIA, of the 98.8 million megawatt hours of electricity produced in Kentucky in 2006, 92.3 percent was from coal-fired sources, 2.6 percent from hydroelectric stations and 0.5 percent from other renewable resources (EIA, 2008b).

As shown in Table 2, renewable electricity generation in Kentucky today is dominated by hydroelectric resources (85 percent) with smaller amounts provided by wood waste (12 percent) and landfill methane (three percent) utilization. Kentucky does not have readily accessible reservoirs of steam, hot water or hot dry rocks for the production of electricity from geothermal resources.

Table 2: Kentucky Renewable Electric Power Industry Statistics (EIA, 2008b)

2006 Generation	Thousand Megawatt-Hours	Percent of State Total
Total Renewable Net Generation	**3,052**	**3.1**
Geothermal	-	-
Hydro Conventional	2,592	2.6
Solar	-	-
Wind	-	-
Wood/Wood Waste	370	0.4
MSW Biogenic/Landfill Gas[†]	88	0.1
Other Biomass	2	-

[†]Kentucky has no significant generation from municipal solid waste (MSW).

Kentucky's Renewable Energy Opportunities

Relative to other parts of the nation, Kentucky does not have significant sources of utility-scale renewable energy. Biomass and hydropower have the greatest potential for high capacity applications, but the state's limited exposure to strong winds, clear sunshine and deep waters implies that the majority of renewable energy systems will be widely distributed and relatively small in scale.

Solar Energy

Kentucky does not receive sufficient direct sunlight to make concentrating solar power a viable option today, but it does receive ample amounts of solar radiation for photovoltaic and solar heating applications (U.S. Department of Energy, Alternative Energy Resources in Kentucky). In this regard, the lack of significant development of solar energy in Kentucky is not because of a lack of solar energy resource, but rather, a reflection of historical economic conditions which have favored fossil-based energy resources.

The solar resources available to Kentucky and much of the United States greatly exceed those of Germany, which leads the world with grid-tied photovoltaic installations, reaching 1,328 megawatts in 2007. Perhaps even more significant, over 40 percent of the German market consists of systems below ten kilowatt capacity (Solarbuzz, 2008 Report).

Solar Photovoltaic Electricity

The state's primary energy consumption in 2025 could be reduced by 12.6 trillion Btu through the widespread deployment of solar photovoltaic (PV) systems. A report from the University of

Kentucky estimates that widespread deployment of 470 megawatts of solar photovoltaic electricity could reduce the state's primary energy consumption in 2025 by 6.3 trillion Btu if 6-kilowatt systems were installed on one out of every five new homes built between 2008 and 2025 (Colliver et al., 2008). Although a similar analysis was not conducted for commercial and industrial sectors, it is reasonable to assume that installed capacity in these sectors would meet or exceed residential growth (SEIA, 2008).

A PV solar capacity of 940 megawatts is high by today's standards, however there are strong signs of explosive growth and investment in the U.S. solar industry. Between 2001 and 2006, domestic shipments of photovoltaic cells and modules increased an average of 50 percent each year (EIA, 2007b) and, whereas approximately 150 megawatts of solar PV was installed in the U.S. in 2007, an additional 800 to 1,500 megawatts of PV capacity is expected each year by 2011 (Koot, 2008).

In Kentucky, a 6-kilowatt grid-tied PV system could be expected to generate about 7,500 kilowatt-hours of electricity over the course of a year. In a region where household electricity consumption averages nearly 1,200 kilowatt-hours per month, approximately half of a home's annual electricity consumption would come from solar power (EIA, 2001). Today, solar PV systems cost about \$7-\$10 per watt of capacity installed. Thus a 6-kilowatt system would be on the order of \$50,000 without incentives or tax credits. Solar PV systems are eligible for a federal tax credit of 30 percent of the system costs. The cost of photovoltaic energy is high today, but newer more efficient solar cells are coming to market to help lower prices. The goal of the DOE's Solar America Initiative is to make solar cost-competitive with conventional electricity by reducing residential solar costs from 32¢ per kilowatt-hour in 2005 to 10¢ per kilowatt-hour by 2015 (DOE, 2008b).

Many state and local governments are pursuing PV installations on public buildings. To do this *successfully, sound public policy, financial incentives, and committed program administrators are* required. The most common benefits associated with public-sector solar programs include (Cory et al., 2008):

- PV can reduce utility peak summer demand.
- PV offers predictability of future utility expenses.
- PV reduces greenhouse gas (GHG) emissions.
- Public-sector PV stimulates the market and motivates other sectors to deploy solar.
- PV promotes the creation of local jobs.
- PV can provide emergency power benefits for critical municipal services during and directly after a disruption to the electrical grid.

Solar Thermal Hot Water

Energy used for water heating is a significant portion of the total energy demand in the commercial and residential sectors. In 2004, water heating in the residential sector consumed about 23 percent of all residential natural gas use, eight percent of all residential electricity use, and about 12 percent of total residential energy expenditures. Nationwide, about eight percent of all end-use natural gas is used to heat water in commercial and residential buildings. Solar water heating (SWH), which uses the sun to heat water directly or via a heat-transfer fluid in a collector, may be particularly important in its ability to reduce natural gas use (Denholm, 2007).

According to the University of Kentucky analysis, if one in five new housing units built between 2008 and 2025 includes solar water heating, the state could reduce its primary energy consumption in 2025 by 2.0 trillion Btu. Many non-residential applications also exist, including swimming pool heating, laundromats, hotels, dormitories, multi-family dwellings, and places with significant food preparation or processing. In total, these applications could amount to 70 percent of residential capacity (McMullen et al., 2008), bringing the total potential for solar water heating in Kentucky to 3.4 trillion Btu.

Wind Energy

Electricity generated from wind is becoming one of the least costly and most readily deployed options for new generation. In 2007, wind projects accounted for nearly 30 percent of all new power generating capacity in the United States. A 2008 report by the U.S. Department of Energy finds that the United States possesses enough affordable resources to contribute 20 percent wind energy to the nation's electricity supply by 2030 (DOE, 2008c).

The Wind Energy Resource Atlas of the United States associates most areas of Kentucky with a class 1 or class 2 wind power designation. A wind power class represents a range of wind power densities (W/m^2) that is likely to be encountered at an exposed site in the area. Large wind turbine applications require class 3 or better wind power. Class 2 areas are considered marginal and class 1 areas are generally unsuitable. Small areas of class 3 wind power are found along the mountain ridges in the extreme southeastern part of Kentucky.

Citing data from a 1991 study by the U.S. Department of Energy's Pacific Northwest National Laboratory, the American Wind Energy Association estimates that Kentucky has 19 square miles of class 3+ areas that are not under land-use or environmental restrictions. Developing these areas and accounting for the potential of small wind systems, Kentucky is believed to have the capacity to generate 34 megawatts of wind energy power on average. Operating over the course of a year, this renewable resource could reduce the state's (primary) energy consumption by 3.2 trillion Btu (Colliver et al., 2008).

Large-scale wind projects in other states have encountered resistance to such issues as:

- Avian and bat mortality rates along migratory routes.
- Sight line obstructions of notable vistas.
- Arbitration of property easements and downstream wind shielding.
- Adverse effects on localized temperature and moisture, especially around agricultural lands.

These issues are likely to diminish in proportion to the smaller size of the wind farms anticipated in Kentucky, but further consideration is justified in order to facilitate development of the wind industry in the state.

Combined Heat and Power

In 2001, the Domtar paper mill near Hawesville, KY installed a combined heat and power system fueled almost entirely from biomass. The system has the capacity to produce 88 megawatts of electricity and one million pounds of steam per hour by burning "black liquor" and other wood byproducts from the plant. Capable of operating at almost 86 percent efficiency, the integrated system requires 23 percent less fuel than typical onsite thermal generation and purchased electricity. The project was recognized by the U.S. Environmental Protection Agency and the Department of Energy with a 2005 Energy Star Combined Heat and Power (CHP) Award.

Biomass Energy

Biomass is plant matter such as trees, grasses, agricultural crops, or other biological material. It can be used as a solid fuel, or converted into liquid or gaseous forms for the production of electric power, heat, chemicals or fuels. Biomass-based electricity generation is considered a relatively cost-effective renewable technology for Kentucky, but the economics generally require placement of the electric generation facility near the feedstock fuel source.

Municipal solid waste (MSW) power plants burn solid refuse from relatively large urban centers. While this type of power plant can be economically feasible, many concerns have been raised about the environmental safety of burning a multitude of domestic, commercial and industrial waste products. This risk can be mitigated by using relatively homogenous waste streams, such as scrap from manufacturing processes, or by presorting the waste content. Kentucky burns negligible amounts of MSW for the generation of electricity.

Landfill Gas

In 2003, East Kentucky Power Cooperative (EKPC) opened the first landfill gas power plant in Kentucky. The plant makes electricity by collecting and burning methane gas in combustion engine-generators. Methane is a natural byproduct of the decomposition of organic waste and a powerful greenhouse gas. By burning methane, landfill gas plants not only supply renewable energy, they also prevent methane from entering the atmosphere. Today, EKPC operates five landfill gas power plants across the state. With a total generating capacity of 16 megawatts, the plants provide enough electricity to power about 8,000 homes.

Landfill gas (LFG) power plants are a variant of MSW technology, where gas from the decomposition of waste is used to fire turbines for electric generation. Municipal solid waste landfills are the second largest source of human-related methane emissions in the United States, accounting for nearly 23 percent of these emissions in 2006. At the same time, methane emissions from landfills represent a lost opportunity to capture and use a significant energy resource. Landfill gas consists of about 50 percent methane, the primary component of natural gas, about 50 percent carbon dioxide, and a small amount of non-methane organic compounds. Using LFG helps to reduce odors and other hazards associated with LFG emissions, and it helps prevent methane from migrating into the atmosphere and contributing to local smog and global climate change (EPA, 2008).

Kentucky has five active LFG power plants and a sixth project is under construction. The five active sites have a combined generating capacity of 16 megawatts (EPA, 2008b). The state's largest landfill, Louisville's Outer Loop, diverts a portion of its methane gas for direct use in a nearby *industrial park. An additional 18 candidate sites and 12 potential sites are identified in the* EPA's database. The theoretical potential of these resources could reduce the state's energy consumption by 5.9 trillion Btu (Colliver et al., 2008).

The decomposition that occurs underground in landfills can be engineered using anaerobic digester (AD) systems. Anaerobic digesters, often referred to as methane digesters, are amenable to biomass resources having high moisture contents. Byproducts from Kentucky's wastewater treatment facilities, ethanol and distiller industries and livestock operations could be converted into biogas using AD technology. Besides energy production, anaerobic digesters offer other benefits including odor reduction, reduced greenhouse gas emissions, and potential pathogen reductions.

A 2003 assessment of wastewater AD plants in Wisconsin concluded that the technology can be cost effective for plants treating at least one million gallons per day (Vik, 2003). According to the USDA, the long-term success of AD systems in the livestock industry has been more limited. In many cases, the AD systems failed, not because of technological shortcomings but because the owner was unwilling to continue with the necessary operation and maintenance. Nonetheless, renewed interest in AD technology over the past five years has led to an increase in the number of vendors marketing complete systems. The most cost effective designs are likely to be installed at larger animal feeding operations and directly use the biogas produced on site. Biogas systems are less complex and thus cheaper to install and operate compared to systems that generate electricity (USDA, 2007).

Maker's Mark Distillery

Maker's Mark Distillery is a straight Kentucky bourbon whisky maker that has had an annual average growth rate of 12 to15 percent over the last 15 years. To allow for further growth and expansion, Maker's Mark had to solve the problem of disposal of its still byproducts (a water/grain mix that's left over after the alcohol is removed from the mash). Traditional disposal uses a Dry House which takes the raw (approximately 10 percent solids) still byproducts and evaporates the water to leave about 80-90 percent solids that can be sold as an animal feed called distiller's dried grains (DDG). Unfortunately, the burgeoning fuel ethanol industry has resulted in a glut of DDG. The over-supply of DDG plus the tremendous amount of energy consumed by a Dry House convinced Maker's Mark that they needed to find a new method to treat their still byproducts.

Maker's Mark chose a 'green' method of treatment. After three years of research, they chose a high-rate anaerobic system from Ecovation Inc. This system captures waste heat used to pre-heat lake water for the mashing process, produces a 42 percent solids animal feed, and most important, produces enough methane gas to replace up to 30 percent of the natural gas used by the plant. Any organics not converted to methane in the anaerobic digester are processed through an aerobic wastewater treatment plant, leaving water pure enough to return to the waters of the commonwealth.

Woody Biomass

Kentucky has great potential for producing renewable energy from woody biomass (Figure 12). Wood energy sources might include woody residues from primary and secondary forest industries (such as bark, sawdust, slabs, trimming and edgings, etc.), residues from logging (tops, unmerchantable sections of stemwood), urban wood residues, woody energy plantations, and a portion of net forest growth that is not currently utilized.

Kentucky is ranked as one of the top five states in the production of industrial wood residues (1.59 million dry tons per year). However, most of these residues, primarily from sawmills, are already utilized as boiler fuel, horse bedding, landscape materials/ mulch, charcoal, and other products. The National Biomass Partnership (NBP) estimates that 3.5 million dry tons per year of underutilized biomass is available beyond what is being produced by Kentucky forest industries. The majority comes from logging residues associated with current harvest levels (1.95 million tons), but the removal of unmerchantable trees and underbrush for fuel deduction thinnings (1.21 million tons) and the diversion of urban residues (0.34 million tons) would also play a role. The NBP believes that another 3.78 million dry tons per year could be realized by using 25 percent of the land not cropped or enrolled in the Conservation Reserve Program to grow short rotation woody crops like hybrid poplar or willow, assuming a nominal biomass yield of 4.5 dry tons per acre per year (NBP, 2007).

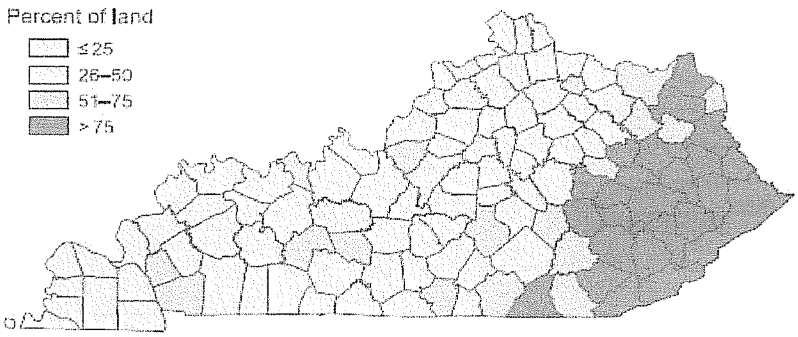


Figure 12: Forested Land Covers 12 million acres (47 percent) of Kentucky (Turner, 2008)

Failure to protect Kentucky's forests from over-harvesting and poor management practices will jeopardize one of the state's largest resources for renewable energy. The woody biomass identified in the National Biomass Partnership report comes from low value sources that are not in direct conflict with Kentucky's wood product industries. However, additional pressures from an emerging energy sector could easily create conflict between the two industries and harm the forest resource base. The use of these resources, in particular the net growth of merchantable trees, will require careful harvests to protect the forests. A renewed focus on forest management education and land-use policies will be necessary to ensure that Kentucky can provide a truly sustainable supply of woody biomass for all its needs.

The net growth of merchantable trees could yield an additional 1.9 million dry tons of biomass potential annually. According to Kentucky's 2004 Forest Inventory and Analysis, Kentucky forests are annually growing more biomass than is being removed. The analysis concludes that approximately one billion board feet of sawtimber, equivalent to 1.9 million dry tons per year, is available from the net growth of merchantable trees (Turner, 2008). Net growth is defined as growth beyond what is removed either through harvesting or loss of forest acreage.

In total, approximately 9.18 million dry tons of biomass potentially could be annually harvested, recovered, or specifically grown for biomass fuel in Kentucky without diverting biomass from existing uses. Assuming a heating value of 8,000 Btu per dry pound, this resource could provide up to 147 trillion Btu of renewable energy potential each year; however, capitalizing on the entirety of this resource is unlikely, despite being technically feasible.

The utilization capacity will eventually be determined by the marketplace with pressure anticipated from carbon management and renewable energy policies at the state and/or federal level. Lacking additional economic analysis and recognizing that only a portion of this resource will be developed, it is assumed that Kentucky's forests will contribute 66.9 trillion Btu of energy in 2025. This is approximately two and a half times more biomass energy than what is being utilized today (EIA, 2008c).

An advantage to woody biomass material is that it can be used to produce a variety of end-use products such as fuels, chemicals and power. It can be burned directly or converted into combustible fuels using thermal and/or chemical processes (Badger et al., 2007). While woody biomass is generally more cost-effective when co-fired with fossil fuels, this approach introduces a number of material handling and material compatibility issues. A bigger concern for older plants is permitting. Many facilities currently operate under permits that were grandfathered in when environmental regulations were strengthened. Such permits often limit the types of fuels they are allowed to burn. As long as they continue to operate as dictated by the original permit, they are not required to upgrade the facility. This creates a possible disincentive for incremental changes even if the outcome is an improvement in overall emissions (Badger et al., 2007b).

It is important to note that the potential for cellulosic ethanol identified in *Strategy 3* does not include the 66.9 trillion Btu per year of woody biomass resources described above. Woody biomass could conceivably be used to produce either electricity or transportation fuel. The end use will be dictated by the market economics defined in part by material and land availability, consumer demand, emerging technologies, financial incentives and government policy. Utility companies will be more favorably inclined to policies that are positive and certain. The current federal Renewable Fuels Standard requires 36 billion gallons of renewable fuels to be used by 2022, of which 16 billion gallons must come from cellulosic resources (RFA, 2008).

Hydroelectric Power

In 2008, the Kentucky legislature authorized the Kentucky River Authority to promote private investment in the installation of hydroelectric generating units on all existing constructed and reconstructed Kentucky River dams under its jurisdiction (LRC, 2008).

The potential for new hydroelectric generation in Kentucky is likely to occur at sites that have an existing impoundment or minimally invasive run-of-river projects. Hydropower development is difficult because of competing uses for water, concerns for fish and wildlife, and the potential for impact by drought. In 1998, the Idaho National Laboratory (INL) conducted a resource assessment of the undeveloped hydropower potential in Kentucky. Forty-seven of the 51 sites assessed in the study already have some type of dam or impoundment, and 65 percent were considered small hydropower, less than 10 megawatts. The total undeveloped hydropower potential was 439 megawatts (INL, 1998).

Large hydro projects require very long lead times and large capital investments, and usually generate significant stakeholder opposition. Three new hydroelectric projects have been announced and two are in the early stages of development that utilize existing infrastructure. The projects range from five megawatts to 105 megawatts with a total generating capacity of 262 megawatts (Overland, 2008).

Assuming a quarter of the 701 megawatts identified in these two reports is developed and assuming a 40 percent capacity factor for hydro, Kentucky could replace 5.4 trillion Btu of fossil-based fuels. The additional capacity represents a 24 percent increase over the 2006 hydropower generation and would bring the state's total hydropower potential to 35.0 trillion Btu.

Hydropower

In 2006, Lock 7 Hydro Partners, LLC began renovating the dormant turbine-generators at Lock and Dam 7 on the Kentucky River near Harrodsburg, KY. Renamed the Mother Ann Lee Hydroelectric Station, the plant consists of three turbines with a total electricity generating capacity of more than two megawatts. The hydro plant is one of only a few dozen to be certified by the Low Impact Hydro Institute for minimizing its environmental impacts on fish, wildlife and other resources. Once fully renovated, Mother Ann Lee is expected to generate 8.3 million kilowatt-hours a year, which is roughly the amount of electricity consumed by 800 U.S. households in a year.

Renewable Energy Markets

Mechanisms for promoting renewable energy include voluntary and mandatory markets. Mandatory markets exist where policy decisions, such as state renewable portfolio standards, dictate that electric service providers include a minimum amount of renewable energy in their electricity supply. To promote portfolio diversification, many states establish set-aside or "carve outs" for higher cost technologies. Without carve-outs, an RPS will generally exhaust low-cost technologies first before maturing other markets (Clean Energy Group, 2008).

Kentucky does not currently have a Renewable Portfolio Standard (RPS). The matter was formally reviewed in the PSC Case 2007-00477 in which the PSC advised that the structure of an RPS as well as the reliability and cost effectiveness of an energy portfolio containing increasing amounts of renewable energy should be reviewed and evaluated. (PSC, 2008b). In setting an RPS for Kentucky consideration must be given to both jurisdictional and non-jurisdictional energy service providers and how the RPS is applied to each.

Voluntary consumer decisions to purchase electricity supplied from renewable energy sources represent a powerful market support mechanism for renewable energy development. Beginning in the early 1990s, a small number of U.S. utilities began offering "green power" options to their customers. Green power represents renewable energy resources and technologies that provide the highest environmental benefit. Customers often buy green power for avoided environmental impacts and to support its greenhouse gas reduction benefits. Many Fortune 500 companies, local, state and federal governments, and a growing number of colleges and universities purchase green power to demonstrate their commitment to the environment and to lead by example (EPA, 2008c).

In Kentucky, all electric utilities regulated by the PSC offer green power to their utility customers. Green power is purchased in blocks of kilowatt-hours with price premiums ranging from 1.67 to 2.75 cents per kilowatt-hour. The 2006 average residential price for electricity in Kentucky was 7.02 cents per kilowatt-hour.

As an alternative to green power, or where green power is not available, individuals and organizations can support renewable energy development by purchasing Renewable Energy Certificates (RECs). A REC represents the property rights to the environmental, social, and other non-power qualities of one megawatt-hour of renewable electricity generation. A REC, and its associated attributes and benefits, can be sold separately from the underlying physical electricity associated with a renewable generation source (EPA, 2008d). RECs provide buyers flexibility in procuring green power across a diverse geographical area, but do not necessarily support local renewable energy projects.

Incentives

Recognizing the benefits of renewable energy, many state, local, utility and federal programs offer incentives to reduce up-front costs. The biggest incentives generally exist in states having a renewable portfolio standard.

Incentives based on installation and system costs are fairly common. These include rebates, tax credits, and tax exemptions. Although easy to implement, these types of incentives are often short-lived and offset a relatively small portion of the initial price.

Performance-based incentives are inherently more complex, but offer greater potential for reimbursement. With this approach, incentives are generally paid out over time based on system production. The incentive could be a direct per kilowatt-hour payment like that used for feed-in tariffs or an indirect payment such as the market value placed on a tradable REC. A feed-in tariff, also known as a renewable energy payment, is a premium rate that is guaranteed over a long-term contract for the generation of renewable energy. With tradable instruments like RECs, the market is left to determine the price.

Challenges to Renewable Energy Production

Financial

Renewable energy markets, until they mature, need predictable, long-term incentives and policy support to function in the near term. A significant barrier to the wide-spread adoption of renewable energy systems is that initial costs are high while the financial savings from avoided energy purchases are low.

Kentucky has not had a major driver to help encourage the use of renewable energy. Only recently were utility-scale, renewable energy facilities included in state tax incentive financing. In 2007, Kentucky passed the "Incentives for Energy Independence Act" which provides incentives for companies that construct, retrofit or upgrade a facility to generate electricity from renewable energy resources. To qualify, the renewable energy facility must generate at least one megawatt of power (50 kilowatts for solar) and incur a minimum capital investment of $1 million (LRC, 2007).

Through 2008, state-wide incentives for homeowners and businesses to install renewable energy systems are limited to the federal tax credit for solar energy contained in the Energy Policy Act of 2005. The credit, recently extended through 2016, covers 30 percent of the cost of a solar PV or solar hot water system up to $2,000. In 2009, the cap will be removed for PV systems only (TIAP, 2008).

Beginning in 2009, Kentucky will offer a tax credit up to $500 for homeowners and up to $1,000 for businesses to install renewable energy systems utilizing wind and solar energy. Relative to the required capital investment, the tax credits are too small to significantly move the market. In order to grow the renewable energy markets in Kentucky, the incentives need to be better aligned with cost-based rates.

Regulatory

Renewable energy, by its nature, is closely tied to the strategy of distributed generation – producing electricity near its point of use. Distributed generation (DG) can provide system-wide benefits in the form of a diversified fuel mix and ease the strain on utility transmission and distribution networks. Often cited impediments to successful development of distributed generation are (PSC, 2008):

- Historically low electricity prices.
- Redundant technical requirements that increase interconnection costs.
- Utility standby charges for backup power.
- Arbitrary electricity prices for systems outside of net metering policies.
- Lack of standard siting requirements.

Two key prerequisites for developing distributed generation projects include the availability of uniform interconnection standards and net metering rules. They are fundamental to the issue of access to the grid on a basis of economic cost.

Standard interconnection rules establish clear and uniform processes and technical requirements that apply to utilities within a state. These rules reduce uncertainty and prevent time delays that clean distributed generation systems can encounter when obtaining approval for electric grid connection. States that modified interconnection rules focusing only on net-metered systems have found these changes were insufficient to encourage renewable DG. This is largely due to the small capacity limits on net-metered systems, which limits larger DG systems from accessing the grid for back-up power.

Kentucky does not have a state-wide interconnection standard although the matter is under review. The PSC initiated Case 2008-00169, in response to Senate Bill 83 of the 2008 Regular Session, to establish interconnection and net-metering guidelines for retail electric suppliers (PSC, 2008). In February 2008, the EPA completed a research project to assess existing state interconnection rules for their DG friendliness. The EPA deemed Kentucky's interconnection standards to be unfavorable (EPA, 2008e) .

The federal government has provided some degree of guidance to states on interconnection policy. Federal Energy Regulatory Commission (FERC) Order 2006, adopted in May 2005, includes three levels of review of DG systems up to 20 megawatts in capacity. Although FERC's interconnection rules for small generators are unlikely to have much impact on distribution-level interconnection (which is generally governed by states), the commission has stated that it hopes states will adopt its rules – with necessary modifications – to promote a more unified interconnection policy around the United States (IREC, 2007).

Net metering is an important tariff issue for DG systems whereby a customer's electric meter can run both forward and backward in the same metering period and the customer is charged only for the net amount of power used. By definition, true net metering calls for the utility to value distributed power generation at the retail rate using one meter. It is a low-cost and easily administered means of promoting direct customer investment in renewable energy.

Kentucky requires net metering for solar, wind, biomass or biogas, and hydro-energy systems with a generating capacity less than 30 kilowatts. If the cumulative generating capacity of net-metered systems reaches one percent or less of a utility's single-hour peak load during the previous year, the PSC may limit the utility's obligation to offer net metering. Kentucky's net metering law allows for excess electricity to be "rolled over" as credit against future consumption, but credits are not transferable when service is discontinued.

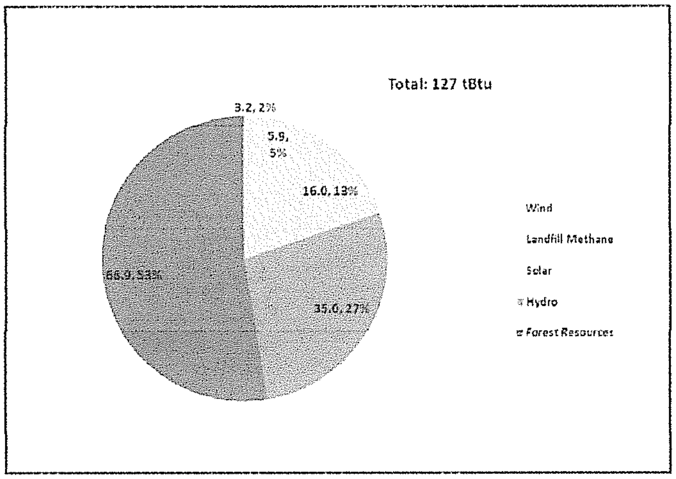
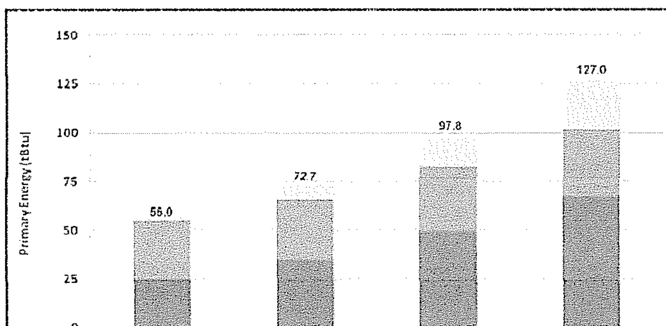


Figure 13: 2025 Renewable Energy Potential for Kentucky



Year	2005	2012	2018	2025
wind	0.0	0.8	1.9	3.2
lfg	1.1	2.2	3.9	5.9
solar	0.0	3.8	9.4	16.0
hydro	29.6	30.9	32.8	35.0
forest	25.3	35.1	49.8	66.9

Figure 14: Renewable Energy Targets to 2025
[1] (2005 data: EIA, 2008c)

Fully Developing Kentucky's Renewable Energy Potential

Using forecast data from the EIA, the University of Kentucky report estimates the state's energy consumption in 2025 will be 2,815 trillion Btu. To achieve a 25 percent goal, Kentucky will need to provide 704 trillion Btu of energy in the form of energy efficiency, renewable energy and biofuels.

The resources identified in *Strategy 2* amount to 127 trillion Btu of renewable energy potential (Figure 13). Combined with 511 trillion Btu from energy efficiency (*Strategy 1*) and 66 trillion Btu from biofuels (*Strategy 3*), Kentucky can realistically achieve a Kentucky REPS goal of 25 percent by 2025.

Using a linear growth model, cumulative targets by resource for the years 2012, 2018 and 2025 are presented in Figure 14. Acknowledging that much of the future resource potential will be in the form of electricity, the units in Table 3 are presented in site-based megawatt-hours.

The 127 trillion Btu of renewable energy identified in *Strategy* 2 does not include agricultural crops and crop residues applied toward biofuels production. Nor does it include renewable energy applications that were not addressed in the reference materials such as methane *production from animal feeding operations and wastewater treatment facilities.*

Clearly, more potential is available and will become available as technologies improve and the markets mature. If climate change legislation is passed and monetary penalties are tied to carbon emissions, many forms of renewable energy generation may become cost competitive and economically attractive.

The primary impediment toward the development of Kentucky's renewable energy potential today is economic viability. The energy potential can be realized using commercially available technologies which can be deployed quickly and scaled over time. Consequently, there is not a significant rationale to delay implementation of Kentucky's renewable resources if appropriate policies and incentives are created to ensure an adequate return on investment.

Developing appropriate policies and mechanisms to spur development of Kentucky's renewable energy sector will require further study. Currently, there are 26 states with mandatory renewable portfolio standards and another six with non-binding goals. To date, no broad, open-ended feed-in tariffs have

Table 3: Renewable Electricity Generation Targets to 2025

Renewable Resource	Thousand Megawatt-Hours (MWh)			
	Existing[1]	2012	2018	2025
Total Generation	**3,052**	**4,509**	**6,694**	**9,244**
Wind Energy	0	69	172	293
LFG / Biogas	88	191	347	528
Solar PV	0	272	679	1,154
Hydropower	2,592	2,708	2,883	3,087
Forest Biomass	372	1,268	2,613	4,182

[1] Existing generation from Table 2.

been created in the U.S., but revisions to RPS policies, necessary to meet increasingly aggressive environmental and economic development goals, have trended toward incorporating elements of feed-in tariffs (Rickerson et al., 2008).

Were Kentucky, on the other hand, to enact an incentive system that depends on tradable RECs, it must be well designed or projected revenues from Renewable Energy Credit (REC) sales will not be reliable enough or great enough to meet capital requirements. A well-designed market must include an adequate penalty for non-compliance to support sufficient REC prices and the requirement for long-term REC contracting. This type of structure provides predictable and sufficient REC revenue streams that better match the life-cycle of federal tax incentives and power purchase agreements (Overland, 2008).

ACHIEVING THE GOAL:

By 2025, Kentucky's renewable energy generation will triple to provide the equivalent of 1,000 *megawatts of clean energy while continuing to produce safe, abundant, and affordable food,* feed and fiber.

Near-Term Actions (1-3 years)

1. State government will lead by example by requiring new or substantially renovated public buildings to utilize renewable energy as a percentage of total energy consumption.

    - The High Performance Building Committee established in HB 2 (LRC, 2008) will establish renewable energy targets for 2012, 2018, and 2025 for new or substantially renovated buildings.
    - The requirements will escalate over time to reflect the state's renewable energy and energy efficiency goals.
2. The EEC will recommend policies and incentives necessary to achieve the state's renewable energy goal. The analysis will:

    - Analyze economic risks relating to carbon emissions and carbon mitigation strategies (*Strategy 6*).
    - As part of implementing the REPS for all suppliers of retail electric power, establish a timeframe for compliance and incremental percentages that will diversify the state's energy supply.
    - Evaluate the costs and benefits to ratepayers and taxpayers of achieving an RPS through different funding mechanisms (PBF, REC trading, feed-in tariff, tax incentives, etc.).
    - Recommend incentive programs necessary to stimulate the deployment of non-electric renewable resources (solar hot water, LFG, woody biomass, etc.).
    - Incorporate and suggest changes to existing state incentives for renewable energy systems (e.g., HB 1 and HB 2).
3. The PSC will develop state-wide interconnection guidelines for renewable energy systems.

4. Kentucky will review its policies and regulations to encourage the responsible use of woody biomass.

   - The Division for Air Quality will examine the rules for New Source Review with the EPA to reduce barriers for distributed generation projects that introduce new fuel sources, yet reduce total annual emissions (e.g., co-firing with biomass).
   - The Division of Forestry will review forestry and land-use policies and regulations to ensure that Kentucky has a sustainable supply of biomass for both its wood and power industries.

Mid-Term Actions (4-7 years)

1. Kentucky will review and make adjustments to its renewable energy policies and incentive programs as capacity grows.
2. Kentucky will amend its interconnection guidelines to allow renewable energy systems up to two megawatts.
3. Kentucky will implement forestry and land-use policies and/or regulations to ensure that Kentucky has a sustainable supply of biomass for its wood and power industries.

Long-Term Actions (>7 years)

1. Kentucky will annually align its renewable energy policies and incentive programs to be compatible with the state's renewable energy goal.

IMPLEMENTATION SCHEDULE

The rate of implementation of the renewable energy resources identified in *Strategy 2* will be greatly influenced by policy and incentives established at the state and federal level. Without intervention, significant movement in the renewable energy sector is unlikely. The recent trend in escalating energy prices will encourage greater adoption of renewable energy systems, but *substantial growth in the market will require aggressive government policies that monetize the true* costs of fossil energy consumption and send clear price signals to renewable energy markets.

ENVIRONMENTAL BENEFITS & LIMITATIONS

Electricity generation is the dominant industrial source of air emissions in the United States today. Fossil fuel-fired power plants are responsible for 67 percent of the nation's sulfur dioxide emissions, 23 percent of nitrogen oxide emissions, and 40 percent of man-made carbon dioxide emissions. These emissions can lead to smog, acid rain, and haze. In addition, these power plant emissions increase the risk of climate change. Renewable energy is receiving increased attention by environmental policymakers because renewable energy technologies have significantly lower emissions than traditional power generation technologies (EPA, 2008f).

Biomass power plants emit nitrogen oxides and a small amount of sulfur dioxide. The amounts emitted depend on the type of biomass that is burned and the type of generator used. Biomass contains much less sulfur and nitrogen than coal; therefore, when biomass is co-fired with coal, sulfur dioxide and nitrogen oxides emissions are lower than when coal is burned alone. Although the burning of biomass also produces carbon dioxide, the primary greenhouse gas, it is considered to be part of the natural carbon cycle of the earth. The plants take up carbon dioxide from the air while they are growing and then return it to the air when they are burned, thereby causing no net increase except for the energy used in agricultural production and gathering and preparation of the biomass as feedstock.

Burning landfill gas produces nitrogen oxides emissions as well as trace amounts of toxic materials. The amount of these emissions can vary widely, depending on the waste from which the landfill gas was created. The carbon dioxide released from burning LFG again is considered to be a part of the natural carbon cycle of the earth. Producing electricity from LFG avoids the need to use non-renewable resources to produce the same amount of electricity. In addition, burning LFG prevents the release of methane, a potent greenhouse gas, into the atmosphere.

The combustion of solid waste for energy raises similar concerns about hazardous air pollutants. Without proper emission control devices or sufficient presorting, the contents used to fuel MSW power plants, including any toxic materials, can be released into the air.

Air emissions from hydroelectric power are negligible because no fuels are burned. However, if a large amount of vegetation is growing along the riverbed when a new dam is built, it will decay in the lake that is created, causing an initial buildup and release of methane, a potent greenhouse gas.

Emissions associated with generating electricity from solar and wind technologies are negligible because no fuels are combusted.

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Energy Efficiency Resource Standards: A Progress Report on State Experience

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June 2011

Report Number U112

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CONTENTS

EXECUTIVE SUMMARY

Inspired by the economic and environmental benefits of energy efficiency, over half the states now embrace specific energy efficiency savings goals, known as Energy Efficiency Resource Standards (EERS). An EERS requires utilities (or related organizations in states where the programs are administered by non-utility entities) to save a certain amount of energy each year, typically expressed as a percentage of annual retail energy sales or as specific energy savings amounts set over a long-term period. The first EERS passed in Texas over a decade ago and since then, utilities, regulators, and consumers across the country have embraced this type of policy to catalyze the implementation of energy efficiency programs to reduce electricity and natural gas consumption in homes and businesses.

The report includes legislative and regulatory background for every state where an EERS policy has been in place for over two years and examines the progress these states have made achieving their goals. Tracking actual energy savings and comparing these results with the required targets, the analysis develops a comprehensive portrait of the performance of twenty states, noting important trends influencing the outcomes thus far.

Across the country, state EERS policies are driving energy efficiency investments and energy cost savings to unprecedented levels, lowering utility bills, improving building comfort, and reducing strains on the utility grid. Overall, the performance of states in comparison to the targets set in EERS policies has been encouraging; most states are meeting or are on track to meet energy savings goals.

The report finds that states' performance meeting energy savings targets is driven by issues such as the clarity and appropriateness of the regulatory framework, the length of time allowed for program administrators to ramp-up programs, and the overall commitment of all parties to invest the proper resources to meet targets. States must overcome these barriers in order to successfully meet EERS targets and states considering the adoption of an EERS should carefully consider these issues in the policymaking process.

ACKNOWLEDGMENTS

The authors would like to thank their many contacts at utilities, commissions, state governments, and nonprofit organizations, as listed below. These contacts participated in interviews and shared their knowledge and insights on state performance meeting energy efficiency resource standards.

We are grateful for the thorough reviews given by Rebecca Stanfield, Natural Resources Defense Council; Sam Krasnow and Derek Murrow, Environment Northeast; and Greg Ehrendreich, Midwest Energy Efficiency Alliance.

Thank you also to ACEEE colleagues Steven Nadel, Glee Murray, Maggie Molina, Max Neubauer, Suzanne Watson, Patrick Kiker, and Eric Schwass for their assistance in the research, review, production, and release of the report. Finally, many thanks to Renee Nida for her work editing this report.

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ENERGY EFFICIENCY RESOURCE STANDARDS (EERS)

A majority of states now have policies in place that establish specific energy savings targets that utilities or related organizations must meet through customer energy efficiency programs. These policies—called "energy efficiency resource standards" (EERS)—are analogous to "renewable portfolio standards," also in place in a majority of the states. An EERS sets multi-year electric or natural gas efficiency targets (e.g., 2% incremental savings per year or 20% cumulative savings by 2020), measured against a baseline of retail sales.[1] Energy efficiency savings are typically measured by the first-year savings of energy-efficient measures installed. EERS policies accelerate and expand the scale of energy savings achieved through utility and related energy efficiency programs.

Historically, energy efficiency program requirements tended to focus on spending levels rather than specific energy savings levels. Energy savings amounts were more of an outcome of the process—a function of initial program budgets, cost-effectiveness screening of measures and programs, and finally the implementation of the programs. Rather than basing policy and program planning on the desired level of energy efficiency savings, the process of planning around budgets resulted in uncertain commitments to actual energy efficiency and often lower savings levels than might have been achievable.

The shift to EERS represents a significant evolution in the treatment of energy efficiency in the utility system. Rather than view energy efficiency in the context of spending requirements to meet some "customer service" obligation, the use of an EERS strategy—with its explicit focus on quantifiable energy savings results—helps directly reinforce the expectation that energy efficiency is a real utility system "resource," and helps utility system planners more clearly anticipate and project the effect of energy efficiency programs on utility system loads and resource needs.

Moreover, EERS targets are generally set at levels that push programs to achieve higher savings than they would have targeted prior to enactment. EERS policies maintain strict requirements for cost-effectiveness so that programs are insured to provide overall benefits to customers. Not only does an EERS drive utilities and program administrators to achieve greater levels of savings, but it also helps ensure a long-term commitment to energy efficiency as a resource, building essential customer engagement as well as the workforce and market infrastructure necessary to sustain high savings levels.

Key Distinctions of EERS Policies

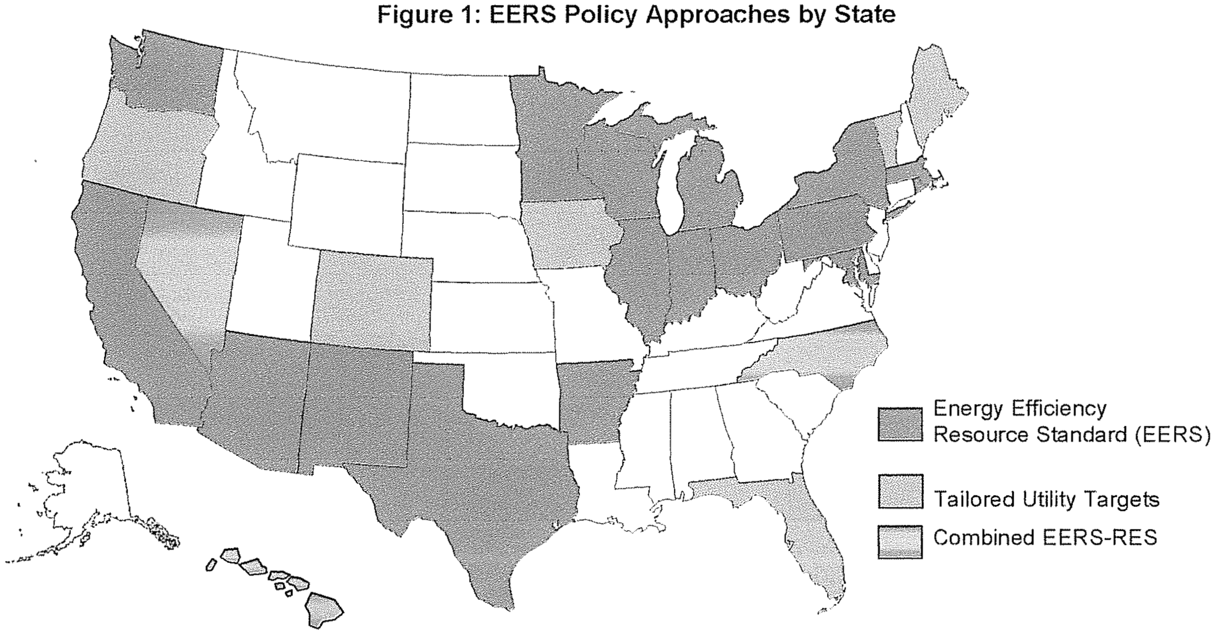
This review finds that EERS policies currently encompass three distinct types of policy approaches, all of which accomplish the same outcome—setting binding, long-term targets for energy efficiency savings from utility programs. The three approaches are a statewide Energy Efficiency Resource Standard, long-term energy savings targets set by utility commissions tailored to each utility and incorporating energy efficiency as an eligible resource in renewable portfolio standards (RPS). While the latter two options may not technically be considered a "standard" in the traditional sense, ACEEE has defined all three approaches as an EERS to avoid confusion and draw focus to the key similarity of all these policies—establishing binding, long-term energy savings targets. In practice, RPS policies that include efficiency have not thus far resulted in aggressive goals, but the policy approach itself has the potential to produce results comparable to the other two mechanisms if properly designed. Tailored utility targets and statewide EERS policies have each been very effective at driving aggressive energy efficiency savings in the states. In addition, certain states such as Massachusetts, Rhode Island, Washington, California, and others have a statewide EERS that operates in the following manner: (1) state law broadly requires utilities to procure all cost-effective efficiency resources ("an efficiency procurement requirement"); and (2) planning processes between the utilities, stakeholder efficiency councils, and public utility commissions (PUCs) then establish the specific percentage savings targets the utilities are required to meet to effectuate the all cost-effective

[1] "Multi-year" is defined as three or more years for the purpose of this report. EERS policies may also set specific gigawatt-hour (GWh) energy savings targets without consideration of percentage of prior-year sales, or as a percentage of load growth.

efficiency procurement requirement.[2] These states have set increasingly aggressive—and fully funded—efficiency savings targets.

Statewide EERS	Tailored Utility Target	Combined EERS–RPS
Typically set by state legislatures and codified by utility commissions, the statewide EERS calls for all eligible utilities to achieve a prescribed level of savings. In efficiency procurement states, the state legislatures have required utilities to invest in all cost-effective efficiency and the specific targets are then set by stakeholder councils and PUCs.	Initiated in a variety of ways, long-term energy efficiency targets in these states are tailored to each specific utility. In each case, law or regulation calls for the establishment of multi-year (3-year+) specific energy savings targets.	Energy efficiency may be accepted as an eligible resource in state renewable energy standards (RPS). In these cases, energy efficiency is measured on a cumulative, rather than annual, incremental basis.

Figure 1: EERS Policy Approaches by State



OBJECTIVES AND METHODOLOGY

Of the twenty-six states with an EERS, only seven were in effect before 2008. While the effects of an EERS have been estimated in numerous ACEEE state policy studies (Neubauer et al. 2011), and ACEEE has examined the results of energy efficiency programs and the potential for meeting aggressive targets (Molina et al. 2010; Kushler et al. 2009), ACEEE has not comprehensively examined states' performance meeting the energy savings targets since 2006 (Nadel 2007). The primary purpose of this report is to track the actual energy savings in states with EERS policies and compare these results with the required targets. The analysis covers every state with an EERS in effect for two or more years, or twenty of the twenty-six EERS states (see Figure 2 for list of states). The report provides a "progress report" profile for every state that includes legislative and regulatory background of the EERS policy, energy savings achieved, and a brief summary of the trends in the state influencing the outcomes thus far.

[2] In some cases, broad goals are set in stage 1 along with the efficiency procurement requirement. For example, Washington's EERS law requires utilities to base their targets on the Northwest Power and Conservation Council methodology, which aims for approximately 1.5% annual savings. The binding targets, however, are set in a separate planning process.

While the report does not detail the broader economic, environmental, and electricity reliability impacts of EERS policies, it should be noted that existing literature confirms that energy efficiency is a well-documented strategy to improve economic productivity, reduce harmful pollutant emissions, and strengthen energy reliability and security (Laitner et al. 2010; National Academy of Sciences 2010). Numerous studies have overwhelmingly portrayed a significant amount of cost savings and indirect economic benefit that would result through cost-effective improvements in energy efficiency of our buildings and industries (McKinsey & Company 2009). Properly implemented EERS policies drive states to realize this potential.

Methodology

The findings of this report are based on extensive primary research and interviews with stakeholders in the states. ACEEE made a good-faith effort to interview at least two stakeholders in each state with knowledge of utility targets and performance. Research was completed May 3, 2011, and while the peer review process did provide updates in some states, the findings of this report should be assumed to be accurate up to this date.

The savings data presented in this report is derived from publicly available utility and commission data, which is reported in varying ways across states. When available, verified net savings are presented, but in some cases, states report gross savings or unverified savings. Because they inhibit reliable comparisons of energy savings, the differences among states' EM&V protocols is an issue that deserves further research. A forthcoming ACEEE report will take on the issue.

A Companion Report

ACEEE is simultaneously releasing a new report, *Energy Efficiency Resource Standards: State and Utility Strategies for Higher Energy Savings,* which thoroughly examines how several states are ramping up energy efficiency programs and policies to achieve aggressive EERS targets. That report focuses on twelve states and offers insight into the policy and programmatic strategies states are implementing to achieve high savings levels. Aside from covering a broader range of states, this report's primary purpose is to track savings levels compared to targets and discuss general trends affecting states' performance. The two reports are complementary and can be separated by the primary research questions asked: Are states meeting EERS targets; how can states ramp-up to and sustain aggressive savings levels?

A Note about Natural Gas

While the primary focus of this report is on electricity EERS policies, general information is included on every state natural gas EERS in effect. When information is readily available, we have included progress meeting goals, but the main focus of the report is to track progress towards meeting electricity efficiency goals.

EERS Policy Status

As of the writing of this report, twenty-six states have an electricity EERS in effect. Thirteen states have a natural gas EERS. The standards and their underlying authorities, listed in order of highest approximate electric annual savings goals to lowest, are summarized below:

Figure 2: Summary of State EERS Policies

States in grey rows have not been in effect for two or more years and are not examined in this report.

State Year Enacted Electric/Natural Gas Policy Type	Energy Efficiency Resource Standard	Reference
Massachusetts[3] 2009 Electric and Natural Gas EERS	Electric: 1.4% in 2010, 2.0% in 2011; 2.4% in 2012 Natural Gas: 0.63% in 2010, 0.83% in 2011; 1.15% in 2012	Electric: D.P.U. Order 09-116 through 09-120) Natural Gas: D.P.U. Order 09-121 through 09-128
Vermont 2000 Electric Tailored Utility Targets (Efficiency Vermont)	~6.75% cumulative savings from 2009 to 2011	30 V.S.A. § 209; VT PSB Docket 5980; PSB Contract[4]
Arizona 2009 Electric EERS	2% annual savings beginning in 2014., 22% cumulative savings by 2020	Docket Nos. RE-00000C-09-0427, Decision No. 71436
Illinois 2007 Electric and Natural Gas EERS	Electric: 0.2% annual savings in 2008, ramping up to 1% in 2012, 2% in 2015 and thereafter Natural Gas: 8.5% cumulative savings by 2020 (0.2% annual savings in 2011, ramping up to 1.5% in 2019)	S.B. 1918 Public Act 96-0033 § 220 ILCS 5/8-103
New York 2008 Electric and Natural Gas EERS	Electric: 15% Cumulative savings by 2015 Natural Gas: ~14.7% Cumulative savings by 2020	Electric: NY PSC Order, Case 07-M-0548 Natural Gas: NY PSC Order, Case 07-M-0748
Minnesota 2007 Electric and Natural Gas EERS	Electric: 1.5% annual savings beginning in 2010 Natural Gas: 0.75% annual savings from 2010-2012; 1.5% annual savings in 2013	Minn. Stat. § 216B.241
Iowa 2009 Electric and Natural Gas Tailored Utility Targets	Electric: Varies by utility from 1-1.5% annually by 2013 Natural Gas: Varies by utility from 0.74-1.2% annually by 2013	Senate Bill 2386 and Iowa Code § 476

[3] The underlying statute, Mass. General Laws c. 25 § 21, requires gas and electric efficiency program administrators to procure "all energy efficiency and demand reduction resources that are cost effective or less expensive than supply."
[4] Goals for 2009 and 2010 were combined. Efficiency Vermont also set goals in previous years in three-year intervals.

State Year Enacted Electric/Natural Gas Policy Type	Energy Efficiency Resource Standard	Reference
Rhode Island 2006 Electric and Natural Gas Tailored Utility Targets	Electric: ~1.3% in 2010; 1.5% in 2011; Council proposed 1.7% in 2012, 2.1% in 2013, and 2.5% in 2014 Natural Gas: ~0.4% of sales in 2011; Council proposed 0.75% in 2012, 1.0% in 2013, and 1.2 % in 2014	R.I.G.L § 39-1-27.7
Ohio 2008 Electric EERS	22% by 2025 (0.3% annual savings in 2009, ramping up to 1% in 2014 and 2% in 2019)	ORC 4928.66 et seq. S.B. 221
Indiana 2009 Electric EERS	0.3% annual savings in 2010, increasing to 1.1% in 2014, and leveling at 2% in 2019.	Cause No. 42693, Phase II Order
Maryland[5] 2008 Electric EERS	15% per-capita electricity use reduction goal by 2015 with targeted reductions of 5% by 2011 calculated against a 2007 baseline (10% by utilities, 5% achieved independently)	Md. Public Utility Companies Code § 7-211
Maine 2010 Electric and Natural Gas Tailored Utility Targets (Efficiency Maine)	Electricity: Annual energy savings of ~1% in FY2011, ramping up to 1.4% in FY2013. Natural Gas: 130 BBtu annually by FY2013	Efficiency Maine Trust: Triennial Plan
Colorado 2007 Electric and Natural Gas Tailored Utility Targets	Electric: PSCo and Black Hills Energy (BHE) both aim for 0.9% of sales in 2011 and increase to 1.35% (1.0% for BHE) of sales in 2015 and then 1.66% (1.2%) of sales in 2019 Natural Gas: Savings targets commensurate with spending targets (at least 0.5% of prior year's revenue)	Colorado Revised Statutes 40-3.2-101, et seq.; COPUC Docket No. 08A-518E; Docket 10A-554EG
Wisconsin 2010 Electric and Natural Gas EERS	Electric: 0.75% in 2011, ramping up to 1.5% in 2014. Natural Gas: 0.5% in 2011, ramping up to 1% in 2013	Order, Docket 5-GF-191
Connecticut[6] 2005 Electric	~1% annual savings 2008-2011	Public Act 07-242 of 2007

[5] The 15% per-capita electricity use reduction goal translates to around 17% cumulative savings over 2007 retail sales.

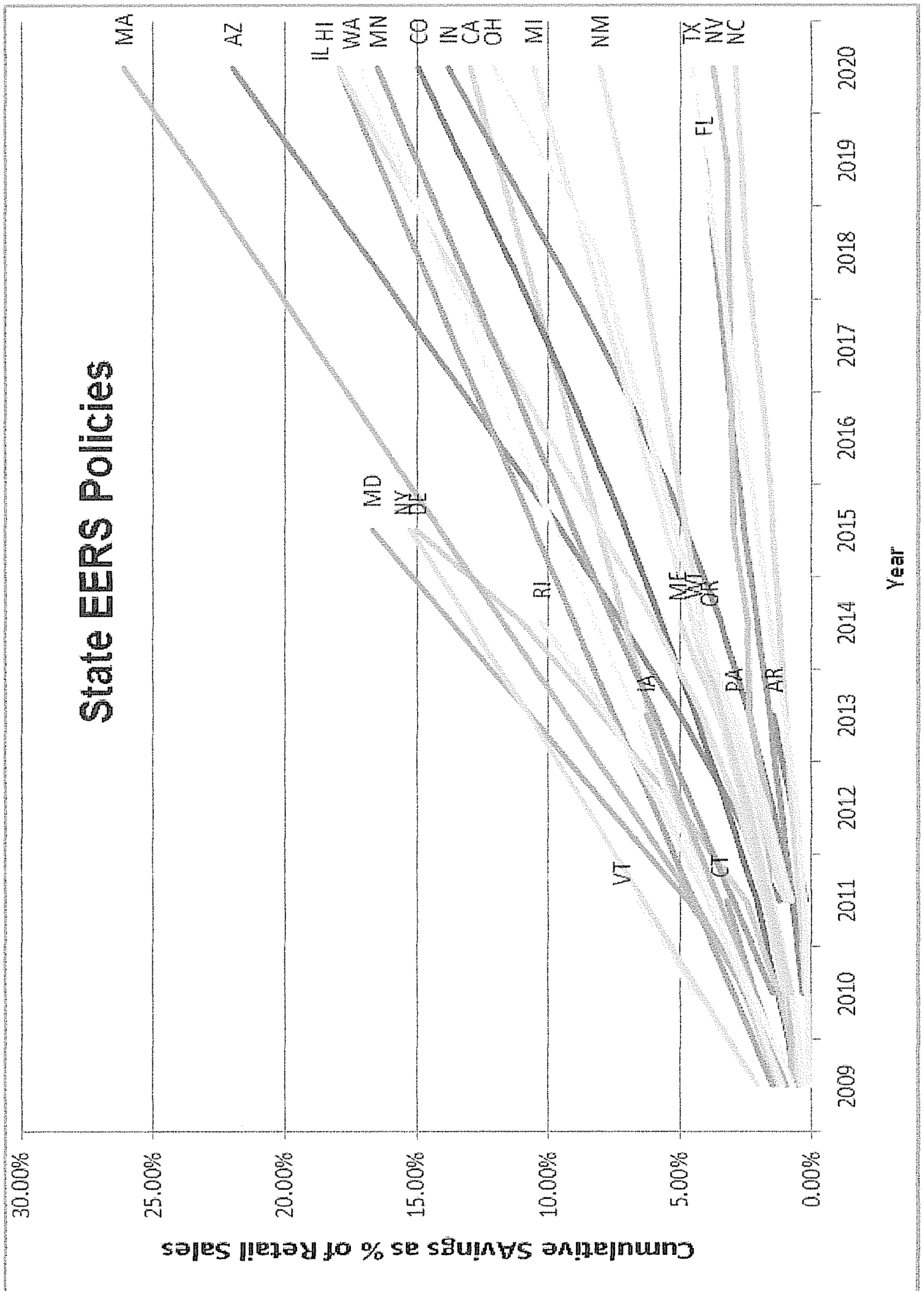
State Year Enacted Electric/Natural Gas Policy Type	Energy Efficiency Resource Standard	Reference
California[7] 2004 and 2009 Electric and Natural Gas EERS	Electric: ~1% annual savings through 2020 Natural Gas: 150 gross MMTh by 2012	CPUC Decision 04-09-060; CPUC Decision 08-07-047; CPUC Decision 09-09-047
Washington 2006 Electric EERS	Biennial and Ten-Year Goals vary by utility. Law requires savings targets to be based on the Northwest Power Plan, which estimates potential savings of about 1.5% savings annually through 2030 for Washington utilities.	Ballot Initiative I-937 WAC 480-109 WAC 194-37
Michigan 2008 Electric and Natural Gas EERS	Electric: 0.3% annual savings in 2009, ramping up to 1% in 2012 and *thereafter* Natural Gas: 0.10% annual savings in 2009, ramping up to 0.75% in 2012 and thereafter	M.G.L. ch. 25, § 21; Act 295 of 2008
Oregon 2010 Electric and Natural Gas Tailored Utility Targets (Energy Trust of Oregon)	Electric targets are equivalent to 0.8% of 2009 electric sales in 2010, ramping up to 1% in 2013 and 2014. Natural Gas: 0.2% of sales in 2010 ramping up to 0.4% in 2014	Energy Trust of Oregon 2009 Strategic Plan
Pennsylvania 2004 and 2008 Electric EERS	3% cumulative savings by 2013	66 Pa C.S. § 2806.1; PUC Order Docket No. M-2008-2069887
Arkansas 2010 Electric and Natural Gas EERS	Annual reduction of 0.25% of total electric kilowatt hour (kWh) sales to 0.75% of total electric kWh sales over the next three years (slightly less for natural gas).	Order No. 17, Docket No. 08-144-U; Order No. 15, Docket No. 08-137-U
New Mexico 2008 Electric EERS	5% reduction from 2005 total retail electricity sales by 2014, and a 10% reduction by 2020	N.M. Stat. § 62-17-1 et seq.

[6] Connecticut does not currently have long-term energy efficiency savings goals that can be defined as an EERS. It is included in this report because it has very recent experience with an EERS policy.

[7] California's goals presented as gross savings. A rough estimate of California's goal as net savings can be achieved by converting gross savings to net savings using the 2009 net to gross conversion factor of 61% (CPUC 2011). Net goals are approximately 0.8% annual savings for the period 2010-2013, dropping to 0.55% from 2014-2020. California's evaluation and attribution methods are some of the strictest in the country, however, which partly explains the low net to gross conversion factor.

State Year Enacted Electric/Natural Gas Policy Type	Energy Efficiency Resource Standard	Reference
Nevada 2005 and 2009 Electric RPS - EERS	20% Renewable energy by 2015 and 25% by 2025—energy efficiency may meet a quarter of the standard in any given year, or 5% cumulative savings by 2015 and 6.25% by 2025.	NRS 704.7801 et seq.
Hawaii[8] 2004 and 2009 Electric RPS - EERS and EERS	Renewable Portfolio Standards include 15% electrical energy savings through 2015. Starting in 2015 all electric utility savings will count towards Hawaii's Energy Efficiency Portfolio Standards (EEPS). EEPS long-term goal is 4,300 GWh reduction by 2030, or 30% of sales.	HRS §269-91, 92, 96
North Carolina 2007 Electric RPS - EEERS	Renewable Energy and Energy Efficiency Portfolio Standard (REPS). Investor-owned: 12.5% by 2021 and thereafter. Energy efficiency is capped at 25% of the 2012-2018 targets and at 40% of the 2021 target.	N.C. Gen. Stat. § 62-133.8 04 NCAC 11 R08-64, et seq.
Texas 1999 and 2007 Electric EERS	20% Incremental Load Growth in 2011 (equivalent to ~0.10% annual savings); 25% in 2012, 30% in 2013+	Senate Bill 7; House Bill 3693; Substantive Rule § 25.181
Florida 2009 Electric Tailored Utility Targets	3.5% energy savings over 10 years.	Docket Nos. 080407-EG – 080413-EG; Order No. PSC-09-0855-FOF-EG
Delaware Pending *Electric and Natural Gas* EERS	Electricity: 15% electricity cumulative savings by 2015 Natural Gas: 10% cumulative savings by 2015.	SB 106

[8] Although Hawaii does not currently have a mandated annual goal for energy efficiency, ACEEE estimates that the current 30% goal will result in 1.5% annual savings through utility programs.


State EERS Policies
Cumulative SAvings as % of Retail Sales
30.00%
25.00%
20.00%
15.00%
10.00%
5.00%
0.00%
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
Year
MA
AZ
IL HI
WA
MN
CO
IN
CA
OH
MI
NM
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CT

As the figure above illustrates, eleven geographically dispersed states have committed to long-term targets to achieve over 10% cumulative annual savings by 2020. Because some state tailored utility targets are set in three-year intervals, the figure shows many states with EERS ramp-ups that only reach 2011, 2013, or 2015. While some states, such as Vermont, expect to extend EERS policies out to another three years, it is unclear whether Connecticut will re-establish long-term utility targets. Below, annual savings targets are drawn out to 2020 and presented as a cumulative total to demonstrate how current state policies, if maintained, would compare.

Table 1: Cumulative Electricity Savings of State EERS Policies Extrapolated to 2020[9]

State	Cumulative 2020 Target	State	Cumulative 2020 Target
Vermont*	27.00%	Wisconsin*	13.50%
Maryland*	26.70%	Maine*	13.40%
New York*	26.50%	Connecticut*	13.14%
Massachusetts	26.10%	California	12.94%
Rhode Island*	25.26%	Ohio	12.13%
Arizona	22.00%	Michigan	10.55%
Illinois	18.00%	Oregon*	10.40%
Hawaii*	18.00%	Pennsylvania*	9.98%
Washington	17.24%	New Mexico	8.06%
Minnesota	16.50%	Arkansas*	6.75%
Iowa*	16.10%	Texas	4.60%
Delaware	15.00%	Florida	4.06%
Colorado	14.93%	Nevada	3.76%
Indiana	13.81%	North Carolina	2.92%

*Savings beginning in 2009 extrapolated out to 2020 based on final year of annual savings required

RESULTS

Across the country, state EERS policies are driving energy efficiency investments and energy cost savings to unprecedented levels. State utility commissions, utilities, and other program administrators have made impressive progress over the last three years implementing EERS policies. This review finds that most states are meeting or on track to meet energy savings targets.

Overall Savings

States with an EERS are achieving significant energy efficiency savings from utility programs, benefitting electric and natural gas customers by lowering utility bills, improving building comfort, and reducing strains on the utility grid. Nine states achieved 1.2% of annual sales or more in their latest reporting year of either 2009 or 2010, an impressive accomplishment considering in 2006 only one state achieved over 1.2% (Molina et al. 2008).[10] Following this group of leading states, an encouraging number of states with an EERS have climbed close to or above 0.5% savings, including states that only recently adopted full-scale utility energy efficiency programs in the Midwest and Southwest.

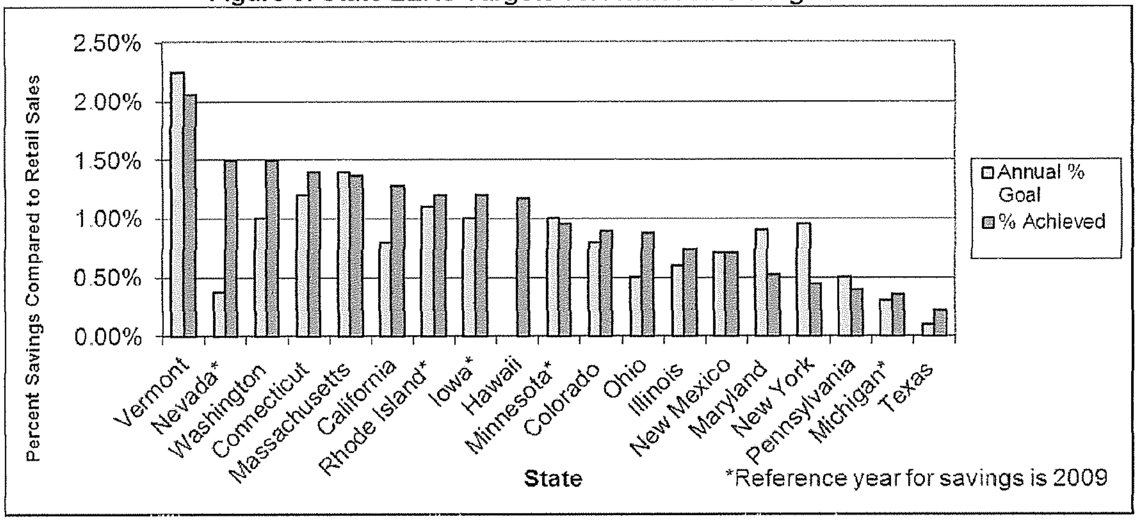
Savings Compared to Targets

Overall, the performance of states in comparison to the targets set in EERS policies has been encouraging; most states are meeting or are on track to meet energy saving goals. Thirteen of the

[9] Colorado savings for PSCo only. Delaware is in the process of formulating rules for its EERS. ACEEE does not extrapolate the goal out to 2020. Other assumptions noted in footnotes of EERS summary table.
[10] Of the nine achieving >1.2%, Nevada, Iowa, and Rhode Island have a reference year of 2009.

twenty states with EERS policies in place for over two years are achieving 100% or more of their goals, three states are achieving over 90% of their goals, and only three states are realizing savings below 80% of their goals.[11]

Figure 3: State EERS Targets vs. Achieved Savings in 2010[12]



While the figure above positively portrays states currently meeting goals, the hard work has yet to come. Targets in many states are still increasing and sustaining aggressive savings levels will be a challenge for states. In states where EERS policies are still ramping up and have low annual savings goals for 2010, such as Ohio, Illinois, and Michigan, meeting goals in the coming years will be challenging and deserves ongoing attention and analysis. Ramping up to high levels of savings in a short period of time is a difficult task, even for states with demonstrated success in energy efficiency program administration. States such as Massachusetts and Minnesota, which are achieving slightly less savings than their targeted goals, are in the midst of major program ramp-ups. Low savings levels during the program ramp-up period have also caused Pennsylvania to fall short of its goals thus far.

Another reason some states are falling below target levels in 2010 is that some EERS policies set long-term goals, which place emphasis on long-term, rather than annual achievements. Pennsylvania and Vermont, for example, set two- and three-year savings targets for 2011, respectively. Past experiences in Vermont and California have demonstrated that it is common for states to make a major push in the final year to make up for lower savings in prior years.[13] This trend seems to be continuing in Pennsylvania, where savings in the first two quarters of its second program year far outpaced levels of its first.

In New York and Maryland, the only states currently achieving less than 80% of their near-term targets, shortfalls can be attributed both to new administrators ramping-up programs as well as the effect of long-term EERS. As explained in further detail below, the combination of delays in program approval and low savings as programs ramp-up has resulted in savings levels, which, if continued, would result in savings below the levels needed to meet long-term goals. New York has approved

[11] While its policy has been in place for over two years, North Carolina has not recorded energy efficiency savings and is thus not included in this tally. Currently, Hawaii's RPS goals allow electrical energy savings to count through 2014. Starting in 2015, electrical energy savings will count towards Hawaii's Energy Efficiency Portfolio Standards.
[12] California gross savings and targets adjusted to net savings using 61% of conversion factor. California savings include partial savings from advanced codes and standards adopted in the state. California, Iowa, and Washington savings and targets based on IOUs reporting savings as of 2010 only. New York based on NYSERDA and utility program administrators only. Colorado includes only PSCo. Ohio does not include First Energy.
[13] Vermont exceeded three year targets for 2006-2008 due to 2008 savings that made up for shortfalls in the prior two years. California came close to meeting 2004-2008 goals due to 2008 savings that made up for shortfalls in the prior two years.

funding, expertise, and an established market that inspire confidence among stakeholders in the state that they can make up for the initial shortfall in the years between now and the long-term target year of 2015. In Maryland, it is less likely utilities will be able to make up the lost ground. The Maryland PSC has not approved utility targets or funding levels sufficient to meet goals set in the EmPOWER Maryland Act. Lacking a strong mandate from the PSC, Maryland utilities have shown uneven commitment to meeting the goals, failing to invest the necessary financial and human resources.

OBSERVATIONS

Aside from the most prominent observation of this report, that states are generally on track to meet or exceed EERS goals, a number of general trends have emerged as states gain experience with EERS policies, which may help states in the varying stages of the policy process.

- Establishing an EERS lays a foundation for increased levels of energy efficiency savings, regardless of prior experience with energy efficiency programs.
- Available data indicates the benefits of programs administered under an EERS substantially exceed the costs.[14]
- Meeting EERS targets requires fair and clear regulation, meaning targets for utilities unaccustomed to energy efficiency must be gradual and the evaluation method for savings clear.
- All parties must be committed to meeting targets. Utilities need to devote proper resources to ensure successful EE programs and Commissions should approve sufficient levels of funding and complementary policies such as cost recovery, performance incentives, and decoupling.
- Ramping-up savings to aggressive levels and sustaining these levels requires programmatic excellence. Tried and true program models work to meet lower goals, but innovative programs reaching all sectors are necessary to achieve deeper savings.

EERS Drives Savings for States of All Types

The EERS policy has driven higher levels of savings in states with established energy efficiency program infrastructure as well as in states without energy efficiency program experience. In Washington and Iowa, for instance, energy efficiency had long been recognized by the major utilities and customers as having significant value. The two states consistently scored well in the ACEEE Scorecard Report, and achieved energy efficiency savings of around 0.6–0.8% of sales from utility programs (Molina et al 2010). EERS policies went into effect in Iowa and Washington in 2009 and 2010, and both states realized a significant boost in savings over previous years. Iowa and Washington achieved 1.2% and ~1.5% savings in 2009 and 2010, respectively.[15] Targets mandated by an EERS policy allow utilities to justify higher spending levels on cost-effective energy efficiency measures. The long-term nature of the goals also provides market certainty regarding the utility commitment to energy efficiency services and technologies, improving the business case for energy efficiency companies in the private sector. States with established energy efficiency programs may have utilities with varying commitment to energy efficiency. The EERS policy can serve to "raise the floor" and drive program development from utilities historically reluctant to offer robust efficiency programs.

States without significant existing energy efficiency programs also benefit from establishing savings targets. In states such as North Carolina, Michigan, and Illinois, the adoption of an EERS prompted utilities to develop and implement programs to benefit customers of all market segments. Without the strong mandate of an EERS, states that have yet to develop energy efficiency programs are less

[14] This is not surprising, given that repeated analyses have shown that utility sector energy efficiency programs tend to be quite cost-effective. ACEEE's most recent report on this subject found that energy efficiency programs saved electricity at an average cost of 2.5 cents/kWh (Friedrich et al. 2009), about one-third to one-fourth the cost of building, fueling and operating a new power plant.
[15] Washington savings based only on IOUs.

likely to begin such an initiative, depriving utility customers of beneficial programs offered in every region in the country.

The Benefits of EERS Outweigh Costs

Ratepayer-funded energy efficiency programs must undergo cost-effectiveness tests that confirm positive benefit-cost ratios greater than one. The standards for cost-effectiveness as well as the types of tests use vary by state, but the presence of rigorous benefit-cost tests prior to program approval assures that efficiency programs and measures installed will likely be cost-effective.[16]

Available data thus far indicates that the benefits of efficiency programs driven by EERS policies have proven to substantially exceed administrator and customer costs. While this report does not comprehensively analyze the cost-effectiveness of energy efficiency programs, anecdotal evidence from a handful of states confirms that energy efficiency is a net beneficial investment.

- Hawaii Energy, the state's third-party Public Benefits Fee Administrator, collects a percent of each electric utilities' customer's bill and is responsible for carrying out Hawaii's energy efficiency and conservation programs. Hawaii Energy achieved net customer energy savings of 113,159 MWh, meeting 97% and 81% of its residential and commercial targets, respectively. Over the lifetime of these rebated and installed measures, cost savings will yield a 546% return on Hawaii's investment of $46.9 million ($17M/$29.9M Ratepayer/Customer Investment) (Hawaii Energy 2010).

- In Illinois, independent analysis of ComEd's programs in its second program year found portfolio the benefit-cost ratio based on the Illinois Total Resource Cost (TRC) test to be 2.84 (Navigant Consulting 2010). Ameren Illinois met its goals in 2009 cost-effectively and its portfolio scored a 2.78 using a TRC test (Ameren Illinois Utilities 2010).

- In 2010, Efficiency Vermont saved 114 GWh at a cost of 4.1 cents per kilowatt-hour (over the life of the measures). Efficiency Vermont spent $35.4 million on efficiency programs, participants spent $21.7 million, and the overall lifetime benefits equaled $136.1 million (Efficiency Vermont 2011).

- In Colorado, Xcel Energy reports that its electric DSM programs had an overall benefit-cost ratio of 3.3 while the gas DSM programs had a benefit-cost ratio of about 1.6. Xcel Energy spent $54.7 million on electric DSM programs and $16.9 million on gas DSM programs last year. The company estimates that electric programs alone will result in $227 million in net economic benefits for customers over the lifetime of energy efficiency measures installed due to its 2010 DSM programs. Gas DSM programs will result in about $15 million in net economic benefits (Xcel Energy 2010).

Clear and Fair Regulation

Critical to the success of states meeting goals is clear and comprehensive regulation of energy efficiency programs. EERS policies must be developed at a pace that allows all stakeholders to engage, submit comments, and adjust to the impending requirements. A methodical process ensures clarity from all parties on critical elements such as eligible technologies, EM&V requirements, and incentives or penalties for compliance and non-compliance. One particular issue that can cause friction is how Commissions decide to measure savings attributable to the EERS. Regardless of what method is chosen, whether on an annual, annualized, part-year, or life-time basis, clarity in the foundational legislative or regulatory authority is of utmost importance, as the cases in Texas and Ohio illustrate. In both cases, elaborated on in the case studies below, a lack of clarity in how energy

[16] ACEEE will release a detailed analysis of utility cost-effectiveness tests later this year.

savings could qualify to meet EERS targets has led to confusion and contention among utilities on what the policy actually requires.

Regulatory lag inhibits utility program administrators from meeting goals. While state utility Commissions should take time approving programs and policies, there is a hazard in approving energy savings targets and assuming programs will be approved in time to meet initial targets. Utility commissions in Maryland and New York took almost a year to approve programs for utilities after their EERS policies were approved. The EERS legislation can hinder states' ability to properly ramp up programs and meet designated goals. Pennsylvania's EERS, for instance, did not require the Utilities Commission to approve programs until five months into the first of two program years. Rather than having the full two years to meet the 1% cumulative savings target, utilities only have 19 months. Setting realistic timeframes for policy and program approval, therefore, can help lay the groundwork for successful EERS performance.

For states without significant existing energy efficiency programs, a gradual ramp-up of programs has been a successful strategy to gain utility acceptance and achieve significant savings as a result. Particularly in states unfamiliar with energy efficiency program administration, gradual ramp-ups allow utilities to develop and manage program administration and implementation at a realistic pace, allowing time for these utilities to seek advice from experienced professionals in the field. While the targets may be low, utilities and states can tout success meeting targets to build momentum for programs, and if performance incentives are in place, allow utilities to understand the financial benefit of meeting goals.

All Parties Must be Committed to Meeting Targets

Energy efficiency targets can only be met in a sustained fashion if regulators, utilities, and program administrators sincerely pursue cost-effective energy efficiency and treat energy efficiency similarly to supply-side resources. For regulators, this means adopting policies complementary to an EERS that improve the business case for energy efficiency, such as cost recovery, mechanisms to address the link between utility sales and profits (e.g., decoupling or lost-revenue recovery), performance incentives, and loading orders calling for the pursuit of all cost-effective energy efficiency. Regulatory commitment to targets also entails adopting cost-effectiveness tests that accurately measure the full costs and benefits of energy efficiency programs. Commissions must permit utilities to fund energy efficiency programs at the levels necessary to achieve targeted savings levels as well.

Aside from failing to provide complementary policies to ensure success, regulators can also include provisions that inhibit states from achieving intended EERS targets. Rate impact caps, or budget caps, can prohibit utilities from making the necessary, cost-effective energy efficiency investments necessary to achieve EERS requirements. Such caps are present in Texas and North Carolina, where it is uncertain whether the caps will lower cost-effective energy efficiency investment, and in Illinois, where the cap will likely trigger a failure to meet the standard in the next few years unless the General Assembly takes action to raise or eliminate the caps (Nowak et al. 2011). Provisions known as "exit ramps," present in Ohio and New Mexico, allow utilities to request permission to lower goals, which may also limit the effectiveness of an EERS policy. EERS policies that include opt-out provisions for industrial customers, as opposed to provisions that allow industrial to conduct "self-direct" programs tied to spending or savings requirements, raise the chances that states will not achieve their cost-effective energy savings potential.

Regulation can only ensure the proper environment for energy efficiency programs to flourish—utilities or third-party administrators must do the work. Successful utilities and third-party programs administrators devote significant human and capital resources to energy efficiency programs. Regardless of how experienced an administrator is with energy efficiency programs, the importance placed on energy efficiency initiatives from corporate leadership is a critical indicator of how well the utility will perform. If energy efficiency targets are embraced by utility leadership, efforts by energy efficiency division staff to meet goals will be welcomed and rewarded, boosting chances of success.

Questionable commitment from utilities and third-party administrators can lead to delays, underperformance, and threats to the policy. Nowhere is this more clear than in states where utilities have publicly opposed EERS policies, seeking to undermine and repeal the authority. In Ohio, First Energy and Dayton Power and Light have mounted strong opposition to the statewide EERS, claiming that its goals will hinder the state's economic recovery. While other utilities in the state such as Duke Energy have met the goals cost-effectively with ease thus far and claim long-term goals, while challenging, are achievable. First Energy fell far short of its first year target and has received a waiver for targets until 2012. Instead of redoubling its efforts to meet targets, it seems First Energy has shifted to an adversarial stance, threatening to hold Ohio back from being a leader in energy efficiency.

Ramping-Up Savings Requires Programmatic Excellence

Demonstrating the will to succeed is important, but actual energy efficiency savings do not derive from organizational commitment alone, but from program implementation as well. Thus, a third critical element to success is programmatic excellence. An analysis of how utilities are ramping up savings to meet EERS targets will be presented in the forthcoming, companion ACEEE report (Nowak et. al. 2011), which will include discussion and examples of the following strategies:

- Increasing energy efficiency funding levels
- Adopting complementary regulatory policies such as decoupling, performance incentives, and loading orders requiring the consideration of cost-effective energy efficiency in resource planning
- Using non-utility program savings (i.e. building codes) to contribute to contribute towards meeting savings standards
- Creating and sustaining collaborative and stakeholder processes
- Capturing lighting savings early and adding new, higher- efficiency technologies to efficiency portfolios beyond CFL's
- Adopting new program design approaches and strategies, including "Deeper, Then Broader"
- Starting programs for new technologies and new customer market segments
- Promoting participation through upstream rebates, more rebates and enhanced advertising

Conclusions and Recommendations

Energy efficiency savings targets effectively advance the objective of increased, long-term energy savings from cost-effective efficiency programs. The findings of this study show that almost every state with an EERS is on track, meeting, or exceeding goals in 2010. This report finds that states' performance meeting energy savings targets is driven by broader issues such as the clarity and appropriateness of the regulatory framework, the length of time allowed for program administrators to ramp-up programs, and the overall commitment of all parties to invest the proper resources to meet targets. States must overcome these barriers in order to successfully meet EERS targets and states considering the adoption of an EERS should carefully consider these issues in the policymaking process.

CASE STUDIES

The following case studies are presented in chronological order based on the effective date of the EERS policy. Each case study provides a brief summary, regulatory and legislative backgrounds, energy savings vs. targets, and a section outlining factors affecting performance.

Texas

Summary

Electric EERS	20% Incremental Load Growth in 2011; 25% in 2012, 30% in 2013+
Applicable Sector	Investor-owned utilities
Natural Gas EERS	None
Authority 1 Date Enacted	Senate Bill 7 May 1999, subsequently amended
Authority 2 Date Enacted	House Bill 3693 May 2007
Authority 3	Substantive Rule § 25.181

Legislative and Regulatory Background

In 1999, Texas became the first state to establish an energy efficiency resource standard, requiring electric utilities to offset 10% of load growth through end-use energy efficiency.[17] Demand growth is the average growth of the five previous weather adjusted peak demands for each utility. In 2007, after several years of meeting this goal at low costs, the legislature increased the standard to 15% of load growth by December 31, 2008 and 20% of load growth by December 31, 2009.[18] The legislation also required utilities to submit energy savings goals. The Public Utility Commission of Texas (PUCT) approved these rules in March 2008.

While the 2007 legislation required utilities to submit GWh savings goals to ensure they did not overly focus on load management, the PUCT determined that utilities could convert their demand savings goals into corresponding energy savings goals each year using a 0.20 capacity factor.[19] The current practice used by Texas utilities is to interpret the term "capacity factor" to be a direct estimate of the fraction of hours in a year when the average peak savings will occur. Thus, the peak to energy savings multiplier used in Texas is 0.20×8760/1,000 MWh/GWh=1.75. This implies a peak to energy use ratio of 0.575, which is much higher than the actual peak to energy use ratio typically in the range of 0.20 to 0.24, which translates to conversion factors ranging from 3-5.

A preferable alternative to setting goals as a percentage of load growth would be to set savings goals as a percentage of baseline electricity sales and demand, which would produce more achievable and equitable targets (Itron 2008).

Recent Developments

In 2010, the PUCT approved Substantive Rule § 25.181, which increased the goals from 20% of electric demand growth to 25% growth in demand in 2012 and 30% in 2013 and beyond.[20] The rule also establishes customer cost caps to contain costs. Texas law requires all electric transmission and distribution utilities (TDUs) to meet energy efficiency goals. Utilities administer incentive programs and retail electric providers and energy efficiency service providers implement the programs. All programs are designed to reduce system peak demand, energy consumption, and/or energy costs and are available to customers in all customer classes.

Energy Savings Achieved vs. Targeted

While Texas has consistently met its energy efficiency goals, the energy efficiency goals have resulted in only modest electricity savings. Between 1999 and 2009, investor-owned utilities' programs in Texas produced 3,574 GWh of electricity savings, which amounts only to 1% of 2009 sales. The energy savings targets set by utilities are about half of the actual levels achieved.

[17] Texas Senate Bill 7
[18] House Bill 3693
[19] Rule defines capacity factor as "The ratio of the annual energy savings goal, in kWh, to the peak demand goal for the year, measured in KW, multiplied by the number of hours in the year."
[20] http://www.puc.state.tx.us/rules/subrules/electric/25.181/25.181.pdf

Table 2: Texas Energy Efficiency Goals vs. Achieved Savings

Year	Demand Goal (MW)	Demand Savings Achieved (MW)	Energy Savings Goal (GWh)	Energy Savings Achieved (GWh)	Energy Savings Goal as % of Energy Consumption of Nine IOUs	Energy Savings Achieved as % of Energy Consumption of Nine IOUs
2007	136	167	238	427.9	0.09%	0.16%
2008	115	202	201	581	0.08%	0.22%
2009	132	240	231	559.8	0.09%	0.21%
2010	142	301	249	548	0.10%	0.21%
2011 (projected)	143	298	251	539	0.10%	0.21%

Source: Texas utility energy efficiency plans and reports

If the load growth targets were to apply to forecast growth in electric retail sales, meaning utilities would have to offset 30% of growth in sales by 2013, this would amount to about 0.5% savings per year beginning in 2013.

Even though the energy efficiency goals do not apply to them, it should be noted that a handful of Texas municipal electric utilities, particularly Austin Energy, generate impressive amounts of energy efficiency savings. Austin Energy and the City of San Antonio generated 188 GWh alone in incremental energy efficiency savings in 2009 (EIA 2011).

Factors Affecting Performance

Collaboration among Stakeholders

Texas's success meeting energy efficiency goals can be attributed to a number of factors, but a few stand out in particular. Utility programs benefit from the ease of use of standard offer program materials for contractors and long standing relationships with contractors. Program managers cite sound electronic tracking systems and websites as contributing to program success, as well as broad reach and effectiveness of market transformation programs. Others note that while there is an inherent risk of inaccuracy, the programs benefit from a process for deeming energy savings, which reduces the cost of verification and measurement.

The relationship between utilities, the PUCT, and program implementers is characterized by a high-degree of collaboration and consultation, which allows for the dissemination of best practices and common barriers. Stakeholders engage in quarterly Energy Efficiency Implementation Project meetings and Texas IOUs formed a voluntary organization for energy efficiency program managers: The Electric Utility Marketing Managers of Texas (EUMMOT). EUMMOT facilitates coordination among program managers to convey common perspectives on energy efficiency program design and implementation; provides for exchange of information on markets and technologies; and advances understanding and participation in efficiency programs.

Rural vs. Urban Utilities

While the state as a whole consistently meets targets, there is a varying degree of success on a utility-by-utility basis. Rural utilities struggle to meet targets, primarily because of the dearth of energy contractors willing to enter the market in sparsely populated areas. Because goals are set as a percentage of incremental growth, utilities such as El Paso Electric that serve fast-growing areas must ramp up savings targets much faster than those with relatively predictable and stable load growth.

Program Design and Marketing

Program managers and advocates in the state roundly state that regulatory barriers inhibiting utilities' ability to market programs directly to customers is a major weakness to of current energy efficiency programs. Stakeholders also assert that it is difficult to improve upon programs or design new ones due to regulatory rigidity. Looking ahead to increased savings goals, Texas program managers and third-parties echo concerns about rural areas, marketing, and inflexible program designs, and also add the inherent contradiction between energy savings and shareholder value that needs to be addressed with a decoupling mechanism (Itron 2008).

Funding Levels

In total, Texas utility energy efficiency program budgets amounted to 0.3% of their revenues in 2009, while the median state spends 0.7%. An analysis by Good Company Associates found that the increase in the goal from 10% of demand growth to 20% in 2010 and 2011 did little to increase spending. The new goals will not significantly impact energy efficiency spending until the recession years are no longer included in the calculation of the five year average growth in demand. Good Company also concludes the cost-caps should not seriously constrain utilities from meeting goals given the modest savings levels.[21] Many utilities exceed the demand goals, however, and as a result, push the limits of the cost-caps. Some companies have already surpassed the cost-caps and others are very close. Unless the PUCT grants a utility the ability to exceed the cost caps, utilities will have to reduce spending in some manner which could result in less demand reduction and energy savings.

Performance Incentives

A utility that exceeds its demand reduction goal within the prescribed cost limit is awarded a performance bonus. A utility that exceeds its demand reduction goal receives a bonus equal to 1% of the net benefits for every 2% that the utility exceeds its goal. The maximum bonus is equal to 20% of the utility's program costs.

Vermont

Summary

Electric EERS	~6% cumulative savings from 2009 to 2011
Applicable Sector	Third-party administrator
Natural Gas EERS	None
Authority 1	30 V.S.A. § 209

Legislative and Regulatory Background

Vermont pioneered the model of a statewide "energy efficiency utility" (EEU) after Vermont enacted legislation in 1999 authorizing Vermont Public Service Board (PSB) to collect a volumetric charge on all electric utility customers' bills to support energy efficiency programs. Vermont PSB created the EEU, Efficiency Vermont, to use these public benefits funds to provide programs and services that save money and conserve energy. Burlington Electric Department (BED) provides DSM services within its own territory. When Efficiency Vermont was created, BED requested, and was granted, authority to run its own programs. BED reports separately on the costs and savings of its programs.

Vermont does not have traditional EERS legislation with a set schedule of energy-savings percentages for each year. Instead, Vermont law requires EEU budgets to be set at a level that would realize "all reasonably available, cost-effective energy efficiency." Compensation and specific energy-savings levels—not "soft" goals or targets—are then negotiated with EEU contractor Vermont Energy Investment Corporation (VEIC). There is not an explicit penalty for non-performance. However, a portion of the compensation Vermont pays the administrator is contingent on meeting stated goals, subject to a monitoring and verification process. If the administrator does not meet

[21] http://www.goodcompanyassociates.com/files/manager/Summary_PUCT_EE_Rule_8-6-10.pdf

stated goals, the state will withhold compensation, and the administrator potentially will be replaced at the end of the three-year period (DSIRE 2011). Efficiency Vermont's current goal is 360,000 MWh of energy savings during the three-year cycle, equivalent to 6.75% of electricity sales.

Moving forward, the goal-setting process will change due to Vermont's new "order of appointment" franchise-like structure. Every 3 years, a "demand resources plan" proceeding will be held. The proceeding will set budgets and goals for the next 20 years, coinciding with the long-range transmission plan to allow for integration of forecasting.[22]

Energy Savings Achieved vs. Targeted

In 2006, efficiency savings were about 1% of sales and by 2008, Efficiency Vermont achieved unprecedented savings levels equal to 2.5% of annual sales, exceeding its MWh goal for the 3-year period. In 2007 and 2008, savings from energy efficiency measures more than offset the average underlying rate of electricity load growth. Savings dropped slightly to 1.6% in 2009, but rebounded significantly in 2010 as the state once again exceeded 2% annual savings. Judging performance on an annual basis, Vermont almost met over 90% of its goal in 2010, but at 3.7% savings over two years, it will need to make up for lost ground in order to meet the three year of 6.75% savings by the end of 2011.

Table 3: Efficiency Vermont Energy Efficiency Savings Achieved vs. Targets

2006-2008 Achieved (MWh)	2006-2008 Goal (MWh)	Percent Attained	2009 Savings Achieved (MWh)	2010 Savings Achieved (MWh)	2009-2011 Goal (MWh)	Percent of 3-year goal attained over 2 years
311,000	261,700	119%	85,000	114,000	360,000	55%

Sources: Efficiency Vermont, 2009 Annual Report; 2010 Savings Claim; 2011 Annual Plan

Factors Affecting Performance

Funding Levels

Substantial increases to the Energy Efficiency Charge (EEC) included within customer rates drove Vermont's success over the last five years. Even though Vermont already had the highest per-capita investment in electric efficiency of any state in 2004, the state legislature passed Act 61 of 2005, which removed the spending cap on the EEU annual budget. The PSB now has flexibility to determine appropriate funding levels in the context of the integrated resource planning process. The PSB increased energy efficiency funding in 2006 from the previous maximum of $17.5 million to $30 million per year for the next three years. The aggressive electric energy efficiency measures have proven to be consistently cost-effective. In 2010, Efficiency Vermont saved 114 GWh at a cost of 4.1 cents per kilowatt-hour (over the life of the measures). Efficiency Vermont spent $35.4 million on efficiency programs, participants spent $21.7 million, and the overall lifetime benefits equaled $136.1 million.

Third-Party, Performance-Based Program Administrator Model

The EEU structure ensures that as an efficiency program implementer, VEIC does not have conflicting incentives. They are not an investor-owned for-profit utility, have no rate base, and thus, no throughput incentive. VEIC is eligible to receive a performance incentive for meeting or exceeding performance goals established in its contracts, directly tying results to compensation. Along with these performance incentives, VEIC staff attributes much of their success to the alignment between their non-profit structure and their mission: to reduce the environmental and economic costs of energy

[22] EEU Structure (Docket 7466)

use. Efficiency Vermont has a deep culture of innovation and experimentation centered solely on saving energy.[23]

Working under a performance-based "order of appointment" allows Efficiency Vermont the flexibility to allocate funds to where they can buy the most energy savings with each budget dollar. Relative to other program administrators, they do more custom projects, and are not constrained to work off of prescriptive measures and prescriptive projects. This allows for incentives to be entirely negotiated with the customer, with Efficiency Vermont effectively buying down the cost of the project or measure until it becomes an attractive investment for them. Within each three-year performance contract period, Efficiency Vermont has program plans which are updated annually. The 2011 plan builds on 2010's established strategies in five markets: business new construction, business retrofit, residential new construction, residential retrofit, and efficient products.

California

Summary

Electric EERS	Commission-set utility targets; ~1% annual savings
Applicable Sector	Investor-owned utilities
Natural Gas EERS	Yes
Authority 1 Date Effective	CPUC Decision 04-09-060 September 2004
Authority 2 Date Effective	CPUC Decision 08-07-047 7/31/2008
Authority 3 Date Effective	CPUC Decision 09-09-047 September 2009

Legislative and Regulatory Background

California is a long-time leading state for its utility-sector customer energy efficiency programs, which date back to the 1970s and have grown and evolved substantially over three decades. Its programs and related energy efficiency policies have had a significant impact on per capita electricity use, which has remained essentially constant over the past 30 years. Following California's 2001 electricity crisis, the main state resource agencies worked together along with the state's utilities and other key stakeholders and developed the California Integrated Energy Policy Report that included energy savings goals for the state's IOUs. The CPUC formalized the goals in Decision 04-09-060 in September 2004. The goals called for electricity use reductions in 2013 of 23 billion kWh and peak demand reductions of 4.9 million kW from programs operated over the 2004–2013 period. The natural gas goals were set at 67 MMTh per year by 2013.

The California Legislature emphasized the importance of energy efficiency and established broad goals with the enactment of Assembly Bill 2021 of 2006. The bill requires the California Energy Commission (CEC), the California Public Utilities Commission (CPUC) and other interested parties to develop efficiency savings and demand reduction targets for the next 10 years. Having already developed interim efficiency goals for each of the IOUs from 2004 through 2013, the CPUC developed new electric and natural gas goals in 2008 for years 2012 through 2020, which call for 16,300 GWh of gross electric savings over the 9-year period. California's current targets are embedded in the approved 2010-2012 program portfolios and budgets for the state's IOUs, which calls for gross electricity savings of almost 7,000 GWh and natural gas savings of approximately 150 MMTh.[24]

[23] For a more detailed discussion of factors driving success in Vermont, see Nowak et al (2011).
[24] A rough estimate of California's gross savings goal as net savings can be achieved by converting gross savings to net savings using the 2009 net to gross conversion factor of 61% (CPUC 2011). Net goals are approximately 0.8% annual savings for the period 2010-2013, dropping to 0.55% from 2014-2020. California's evaluation and attribution methods are some of the strictest in the country, however, which partly explains the low net to gross conversion factor.

Table 4: Goals and Budgets for the 2010-2012 Program Cycle

	PG&E	SCE	SDG&E	SoCal	Total
2010-2012 Program Cycle Electricity Savings (Gross GWh)	3,100	3,316	539	-	6,965
2010-2012 Program Cycle Natural Gas Savings (Gross MMTh)	48.9	-	11.4	90	150.3
2010-2012 Budgets (millions)	$ 1,338	$ 1,228	$ 278	$ 285	$ 3,129

Energy efficiency is the first priority in California's loading order for energy resources. This was first acknowledged in California's 2003 Final Energy Action Plan I. Under Public Utilities Code Section 454.5(b)(9)(C), investor owned utilities are required to first meet their unmet resource needs through *all available energy efficiency and demand reduction resources that are cost effective, reliable, and* feasible.

Energy Savings Achieved vs. Targeted

California IOUs' evaluated net savings for the program period between 2004 and 2008 fell slightly short of the Commission's adopted goals, achieving 9,442 GWh of savings, or about 1% annually throughout the program period.[25] The utilities plan to make up for these shortfalls in the 2010-2012 program cycle.

Table 5: 2004-2008 California Achieved Savings vs. EERS Targets

	PG&E	SCE	SDG&E	SoCal	Total
2004-2008 Program Cycle Electricity Target (Net GWh)	4,313	4,788	1,387	-	10,488
Actual Savings (Net GWh)	4,184	4,278	979	-	9,442
2004-2008 Program Cycle Natural Gas Targets (Net MMTh)	64	-	13	77	154
Actual Natural Gas Savings (Net MMTh)	77	-	12	70	159

Source: CPUC, Energy Efficiency 2006-2008 Interim Verification Report. 10/15/2009

The CPUC and the utilities are cautiously optimistic about the utilities meeting the 2010-2012 program savings goals. Saving goals for the California IOU plans must be met over the full 3-year cycle (not annually). Based on non-binding goals for 2010, IOUs are exceeding electricity goals and are close to meeting natural gas goals.[26]

[25] Compared to 2008 IOU retail sales as reported by EIA

[26] Program performance reports to-date for the California IOU programs are posted in a highly usable format at http://eega.cpuc.ca.gov/

Table 6: 2010 California Achieved Savings vs. 2010 Portion of 2010-2012 EERS

	PG&E	SCE	SDG&E	SoCal	Total
2010 Program Cycle Electricity Goal (Gross GWh)	964	1,117	195	-	2,276
2010 Actual Savings (Gross GWh)	1,425	2,000	265	-	3,694
2010 Program Cycle Natural Gas Goal (Gross MMTh)	15.6	-	3.5	28	47.1
2010 Actual Natural Gas Savings (Gross MMTh)	16.9	-	1.1	21.9	39.9

Source: California Energy Efficiency Groupware Application

Factors Affecting Performance

A full discussion of California's programmatic successes can be found in (Nowak et al. 2011). Broadly, California's experience in program planning and customer engagement contributes greatly to its success. Complementary policies such as decoupling and performance incentives also improve the environment for utility energy efficiency programs. Utilities are given program and budget flexibility so that they may shift funding from unsuccessful programs to successful programs, which contributes to the utilities' success in meeting the energy efficiency savings goals.

Hawaii

Summary

Electric EERS	Starting in 2015 all electric utility savings will count towards Hawaii's Energy Efficiency Portfolio Standards (EEPS). EEPS long-term goal is 4,300 GWh reduction by 2030.
Applicable Sector	One Investor-owned utility with three subsidiaries located on Oahu, Hawaii, and Maui, one rural electric cooperative located in Kauai
Natural Gas EERS	None
Authority 1 Date Enacted Date Enacted	HR 1464 6/25/2009 7/1/2009
Authority 2 Date Effective	HRS §269-91 12/31/2003

Legislative and Regulatory Background

Energy efficiency is included within the definition of "renewable electrical energy" in Hawaii's Renewable Portfolio Standard (RPS), which was codified in HRS §269-91, et seq., and amended in 2006, 2008, and 2009. The RPS requires investor-owned utilities and rural electric cooperative utilities to use "renewable electric energy," which includes energy efficiency measures, to meet 10% of net electricity sales by the end of 2010, 15% by 2015, 25% by 2020, and 40% by 2030. The Public Utilities Commission may assess penalties against a utility for failing to meet the RPS, unless the failure was beyond the reasonable control of the utility. Beginning in 2015, electrical energy savings will no longer be able to count toward Hawaii's RPS, and will instead count towards Hawaii's Energy Efficiency Portfolio Standards.

Recent Developments

Legislation enacted in 2009 (HR 1464) established a formal and separate energy efficiency portfolio standard (EEPS) that sets a goal of a 4,300 GWh reduction by 2030 (equal to about 40% of 2007 electricity sales). The Public Utilities Commission (PUC) must establish interim goals to be achieved by 2015, 2020, and 2025 and may adjust the 2030 standard to maximize cost-effective energy-efficiency programs and technologies. The PUC has yet to establish rules for the stand-alone EEPS, so the current energy efficiency targets in Hawaii are set in its RPS policy.[27]

Shortly before the issuance of the stand-alone EEPS, Hawaii's energy efficiency program administrative structure underwent major changes. In June 2006, the Hawaii State Legislature enacted legislation to create a public benefits fund (PBF) for energy efficiency and demand side management.[28] This legislation granted authority to the Public Utilities Commission (PUC) to develop the details of the third-party administered public benefits fund. In December 2008, the PUC issued an order in Docket No. 2007-0323, outlining the structure of the PBF.[29] In July 2009, the Hawaiian Electric Companies' energy efficiency programs were consolidated into a single program, Hawaii Energy, operated by R.W. Beck, a subsidiary of Science Applications International Corporation (SAIC). Kauai Island Utility Cooperative (KIUC) continues to operate energy efficiency programs independently.

As of the writing of this report, most of the details of Hawaii's EEPS are under consideration by the PUC. The rules that come out of the proceeding will determine interim targets, and of particular importance, whether or not to provide incentives for compliance or penalties for non-compliance. Reducing the overall 4,300 GWh goal is not an option at this time. Hawaii seems committed to energy efficiency and renewable energy, as it recently adopted a statewide goal of reducing its reliance on imported fossil fuels by at least 70% by 2030.

Energy Savings Achieved vs. Targeted

As of 2010, Hawaii utilities achieved 19.0% of its renewable portfolio standard, 8.1% of which derived from cumulative, annualized energy efficiency savings over the policy period, easily meeting the 2010 RPS goal of 10%. In its first year of operation (July 2009-July 2010), Hawaii Energy achieved net customer energy savings of 113,159 MWh, meeting 97% and 81% of its residential and commercial targets, respectively.[30] Over the lifetime of these rebated and installed measures, cost savings will yield a 546% return on Hawaii's investment of $46.9 million ($17M/$29.9M Ratepayer/Customer Investment).

Table 7: Hawaii Energy First Year Program Performance

PY 2009 Target (MWh)	PY 2009 Achieved Net Savings (MWh)	Achieved Savings as % of retail sales*
126,023	113,159	1.17%

*Based on 2009 sales of all HECO companies

The savings levels achieved by Hawaii Energy are impressive compared to the HECO utilities' savings of 57,429 MWh in 2009, which accounted for 0.6% of sales (including Hawaii Energy for the second half of 2009). KIUC reported DSM savings of 19,217 MWh in 2009, or 4.4% of its sales in that year—an impressive achievement.[31]

[27] Docket No. 2010-0037
[28] http://www.capitol.hawaii.gov/hrscurrent/Vol05_Ch0261-0319/HRS0269/HRS_0269-0121.htm
[29] http://www.dsireusa.org/documents/Incentives/HI14R.pdf
[30] Hawaii Energy: Annual Report PY 2009, December 15, 2010
[31] 2010 HECO and KIUC RPS Status Reports, Year Ending 12/31/09. Does not include renewable displacement technologies (i.e. solar hot-water)

Factors Affecting Performance

Decoupling and Performance Incentives

In August 2010, the Hawaii PUC issued its final Decision and Order approving the implementation of the decoupling mechanism for the Hawaiian Electric Company (HECO) companies. Utilities are required to report on their performance of commitments made in the Energy Agreement in their rate cases as the basis for review, modification, continuation or possible termination of the decoupling mechanism.[32]

Hawaii Energy is compensated by the Commission for satisfactory performance of its contract. KIUC has not requested incentives. The most recent bill establishing an Energy Efficiency Portfolio Standard (EEPS) allows the PUC to establish incentives and penalties based on performance in achieving the EEPS.

Connecticut

Summary

Electric EERS	All cost-effective efficiency procurement requirement for electric and natural gas utilities that needs to be implemented. A stakeholder Council called the Energy Conservation Management Board helps to review, provide crucial input into utility proposals to invest in all cost-effective efficiency resources. Combined RPS/EERS 2007-2010 and commission-set utility targets; ~1% annual savings 2008-2011
Applicable Sector	Investor-owned utility, municipal utility
Natural Gas EERS	None
Authority 1 Date Enacted Date Effective	Public Act 07-242 of 2007 June 4, 2007 July 7, 2007

Legislative and Regulatory Background

Connecticut has an all cost-effective efficiency procurement requirement for electric and natural gas utilities that needs to be implemented. It also has a stakeholder Council called the Energy Conservation Management Board comprised of representatives of commercial, industrial, residential, low income, and environmental interests that helps to review, provide crucial input into, and oversee the utilities' efficiency program. Connecticut established a renewable portfolio standard (RPS) several years ago and expanded it in 2005. Specifically, in June 2005, the Connecticut legislature adopted legislation that adds new "Class III" requirements covering energy efficiency and combined heat and power plants (CHP). Under the new Class III requirements, electricity suppliers must meet 1% of their demand through using efficiency and CHP by 2007 and 4% by 2010. No additional Class III resources are required after 2010. Class III resources include: customer-sited CHP systems, with a minimum operating efficiency of 50%, installed at commercial or industrial facilities in Connecticut on or after January 1, 2006; (2) electricity savings from conservation and load management programs that started on or after January 1, 2006; and (3) systems that recover waste heat or pressure from commercial and industrial processes installed on or after April 1, 2007. The revenue from these credits must be divided between the customer and the state Conservation and Load Management Fund, depending on when the Class III systems are installed, whether the owner is residential or nonresidential, and whether the resources received state support.

Distribution utilities and other power distributors are responsible for meeting the goals. Existing energy efficiency programs can be used to help meet the goals, starting in 2006. Third-party providers can also earn savings certificates and sell these to power providers that have Class III

[32] See HI Docket 2008-0274.

obligations. Under the legislation, certificate values can range between $0.01 and $0.031 per kWh of savings.

The 2007 Electricity and Energy Efficiency Act (H.B. 7432) strengthened these requirements by enacting complementary policies, including policies covering energy savings from waste heat recovery. The law also requires utilities to adopt decoupling and enables performance incentives.[33] A key provision of the Act is that it requires utilities to achieve resource needs through "all available energy efficiency resources that are cost-effective, reliable and feasible." The DPUC has interpreted this mandate overly restrictively, however, focusing only on capacity needs, and has not approved funding increases to achieve all cost-effective energy efficiency.[34]

The distribution companies must submit biennial assessments of energy and capacity requirements looking forward three, five and ten years, as well as plans to "eliminate growth in electric demand" and to achieve other demand-side and environmental objectives. The Connecticut Energy Advisory Board (CEAB) reviews the plans before they are submitted to the Department of Public Utility Control (DPUC), along with CEAB comments and analysis. In a separate proceeding, the DPUC reviews the annual Conservation and Load Management (CLM) Plan, which is developed by the utilities with oversight by the Energy Conservation Management Board (ECMB), which is appointed by the DPUC. Connecticut electric utilities adopt savings targets through annual CLM Plans. The ECMB oversees the Connecticut Energy Efficiency Fund (CEEF), which is primarily supported by monthly charges on customers' bills. CEEF was created in 1998 to address increasing energy demand and rising costs. With oversight by the ECMB and its consultants, the utilities administer the energy efficiency programs.

In its 2008 decision approving the combined 2009 CLM Plan submitted by the states' major utilities and the Energy Conservation Management Board, the DPUC ordered that the 2010 plan establish broader, longer-term goals.[35] Connecticut utilities did not include long-term goals in the joint 2010 or 2011 Plans, but goals for programs do exceed 1% annual savings in 2010 and 2011. The 2010 CLM Plan was approved, but the Department expressed concern that long-term goals were not adopted.[36] However, utilities are reluctant to include long-term goals without commitment from the DPUC to increase levels of funding necessary for aggressive long-term energy efficiency goals. The DPUC has shown no indication it will approve additional ratepayer funding for electric programs beyond the current statutorily-mandated ratepayer charge. Recent energy efficiency budget raids described below have fostered uncertainty that limits the utilties' desire to plan out energy efficiency over a long period of time.

Energy Savings Achieved vs. Targeted

Connecticut has been among the national leaders in energy efficiency savings for many years. As the table below illustrates, the state's CEEF-funded programs have been near or above the 1% annual savings for three consecutive years, meeting CLM goals in two of the last three.[37] These figures include programs administered by both IOUs and municipal utilities.[38]

[33] Currently, only United Illuminating uses a full decoupling mechanism. The DPUC has not ordered full decoupling for other gas or electric utilities as of the printing of the report. All utilities are eligible for performance incentives.
[34] Docket 10-02-07
[35] Docket 08-10-03
[36] Docket 09-10-03, Department Order March 17, 2010, pgs 56-58
[37] Since CHP is included in the Class III targets, comparing energy efficiency savings to the RPS goals would not be accurate. Currently, there is no analysis of progress towards meeting Class III RPS targets.
[38] For most recent information on municipal utilities' performance, see Energy Efficiency Services 2009 Annual Report, Connecticut Municipal Electric Energy Cooperative.

Table 8: Connecticut Statewide Energy Efficiency Savings vs. Goals 2008-2011

	2008		2009		2010		2011	
	Goal	**Actual**	**Goal**	**Actual**	**Goal**	**Actual**	**Goal**	**Actual**
Electric Energy Efficiency Savings (GWh)	250	368	277	237	360	423	325	N/A
As Percent of Sales*	**0.8%**	**1.2%**	**0.94%**	**0.8%**	**1.2%**	**1.4%****	**1.1%**	N/A

Source: 2009, 2010 and 2011 CLM Plans
Note: Data includes Low-income programs
*Based on same year sales
**Based on 2009 Sales

Factors Affecting Performance

Funding Levels

Within the new framework created by the Electricity and Energy Efficiency Act, spending increases have been a major factor enabling and sustaining the attainment of higher energy savings. The utility energy efficiency programs have the infrastructure and capabilities in place to acquire all cost-effective savings, but now these funding increases have been stopped and in some cases reversed.

Program plans—designed by the utilities to meet the explicit legal requirement for all cost effective energy savings—have been approved by ECMB, but funding increases have been blocked at the DPUC. At UI, the efficiency program budget is dropping. Budget changes have been caused by a few factors, including years in which unspent funds were carried over from previous years, sometimes due to DPUC orders to freeze programs for budgetary reasons. Changes also occurred due to influx of stimulus money. Budget decreases have also been caused by the state re-allocating efficiency funds to cut budget deficits. Public Act 10-179 will reallocate approximately $19 million from the Conservation and Load Management Fund in 2012 and $27 million annually from 2013 through 2018 to cut the deficit.[39]

In 2009, electric efficiency program budgets dropped from $104 million to $73 million, which correlated to a savings drop from 354 GWh to 237 GWh. Even as the budgets rebounded in 2010, uncertainty persists about future levels of funding. It is also unclear whether Connecticut will establish a new set of long-term goals. The DPUC did not adopt higher savings goals proposed by the CEAB, utility program administrators, and the Energy Efficiency Board in the last two Integrated Resource Plans (IRPs), which were equivalent to about 20% energy savings over ten years. Since the DPUC has failed to adopt and fund long-term goals in its 2011 CLM plan, Connecticut no longer has a policy that can be characterized as an EERS.

Decoupling and Performance Incentives

Currently, only United Illuminating uses a full decoupling mechanism, adjusted annually. During annual hearings, the Energy Conservation Management Board (ECMB) reviews the past year's results relative to the established goals and determines a performance incentive for the distribution utilities for achieving or exceeding the goals. The incentive, referred to as a "management fee," can be from 1-8% of the program costs before taxes. The threshold for earning the minimum incentive (1%) is 70% of the goal. At 100% of the goal, the incentive would be 5%. At 130% of goals, it would be 8%. Program costs are recovered through rates.

[39] Currently under consideration, SB1157 would restore the funds with surplus anticipated to be announced at the beginning of May.

Nevada

Summary

Electric EERS	Energy Portfolio Standard: 25% Renewable energy by 2025—energy efficiency may meet a quarter of the standard in any given year, or 6.25% *cumulative* savings by 2025.
Applicable Sector	Investor-owned utilities, Retail Suppliers
Natural Gas EERS	None
Authority 1 Date Enacted	NRS 704.7801 et seq. 1997

Legislative and Regulatory Background

In 1997, Nevada established a renewable portfolio standard (RPS) as part of its restructuring legislation. Assembly Bill (AB) 3 of 2005 revised the RPS, increasing the portfolio requirement to 20% by 2015 and allowing the utilities to use energy efficiency to help meet the requirements. Amendments in Senate Bill 358 of 2009 raised the standard to 25% by 2025. Energy efficiency measures qualify if they are subsidized by the electric utility, reduce demand (as opposed to shifting peak demand to off-peak hours), and are implemented or sited at a retail customer's location after January 1, 2005. Energy efficiency savings can meet up to a quarter of the total standard in any given year. AB 1 of 2007 expanded the definition of efficiency resources to include district heating systems powered by geothermal hot water (DSIRE 2011).

The Public Utilities Commission of Nevada (PUCN) established a program to allow energy providers to buy and sell portfolio energy credits (PECs) in order to meet energy portfolio requirements. The number of kWh saved by energy efficiency measures is multiplied by 1.05 to determine the number of PECs. For electricity saved during peak periods as a result of efficiency measures, the credit multiplier is increased to 2.0. PECs are valid for a period of four years.

Since they are cumulative savings goals, the 25% target in 2025 will require only 6.25% of its sales in 2025 to be met with energy efficiency *over a twenty-year period*. The average annual savings goals for periods 2009-2011, 2011-2013, and 2013-2015 will be 0.375%, dropping to 0.25% for the next two five year intervals.

Table 9: Nevada Energy Portfolio Standard Goals

Year	Renewables Requirement (% of sales)	EE Allowed (Total Annual) (% of Sales)
2005	6%	1.25%
2007	9%	2.25%
2009	12%	3.00%
2011	15%	3.75%
2013	18%	4.50%
2015	20%	5.00%
2020	22%	5.50%
2025	**25%**	**6.25%**

Energy Savings Achieved vs. Targeted

Since energy efficiency has been deemed an eligible resource in Nevada's RPS, the state's utilities have ramped up energy efficiency programs to meet the 25% cap in each year. The RPS policy applies to Nevada's two investor-owned utilities (Nevada Power and Sierra Pacific Power) and one retail electricity supplier (Shell Energy). Sierra Pacific and Shell Energy met their full RPS requirements while Nevada Power achieved 82% of the non-solar resource requirement. Each entity reached the 25% cap for energy efficiency. Nevada's IOUs achieved impressive savings from energy efficiency programs in 2009, substantially exceeding the cap on energy efficiency set in its portfolio standard.

Table 10: 2009 Nevada IOU Energy Efficiency Savings

Utility	2009 Achieved Savings (MWh)	% of Retail Sales (based on 2009 sales)
Nevada Power*	335,816	1.6%
Sierra Pacific**	102,806	1.3%

*Source: NPC 2010 Annual DSM Update Report
** Source: Sierra Pacific Power Company 2010 DSM Update Report

Factors Affecting Performance

Both utilities consider energy efficiency and conservation as the first leg of a "Three-Part Strategy" to meet customer energy needs. The programs offered reach every customer segment and have been thoroughly examined to ensure effectiveness. The latest plans scaled up successful programs and re-designed those in need of support.

Funding Levels

The spending levels proposed by the utilities and approved by the PUCN will produce savings far exceeding those allowed in the Portfolio Standard. Nevada Power will ramp up spending from $47.6 million in 2009 to $76.4 million in 2012. The increased spending will also continue to drive high savings levels, as each utility has demonstrated in their latest DSM plans. The drop in savings in 2012 shown for both utilities is due to the inability of the utilities to claim savings on installations of CFLs because of a Nevada law that eliminates most incandescent lamps from the market, starting in 2012.

Table 11: 2010-2013 Projected Energy Efficiency Savings for Nevada IOUs

Utility	2010	2011	2012	2013
Nevada Power	201,607	215,014	149,609	N/A
Sierra Pacific	N/A	85,380	43,500	44,780

Source: NPC: Docket No. 10-02009 (Approves 2010-2012 DSM Plan) and approved budgets (via SWEEP); SPP: 2011-2013 DSM Plan

Rhode Island

Summary

Electric EERS	A 2006 state law requires the electric distribution utility to procure all cost-effective efficiency resources through a 3-year Efficiency Procurement Plan and requires full funding of the Plan. After the required review and input by a key stakeholder efficiency council (which included a unanimous 7-0 vote), the Commission approved and fully funded the 2009-2011 Efficiency Procurement Plan which includes electric utility savings targets of 1.12% in 2010, and 1.36% in 2011. The Energy Efficiency Council has proposed savings target of 1.7% in 2012, 2.1% in 2013, and 2.5% in 2014, which are currently being reviewed by the Commission.
Applicable Sector	Investor-owned utilities
Natural Gas EERS	As of 2010, state law newly requires the natural gas utility to procure all cost-effective efficiency resources through a 3-year Efficiency Procurement Plan and requires full funding of the Plan.

	The Commission has approved natural gas efficiency savings for National Grid of 56,145 Annual MMBtu Savings in 2011 (~0.29% of sales). The Energy Efficiency Council has proposed savings target of 0.75% in 2012, 1.0% in 2013, and 1.2.% in 2014, which are currently being reviewed by the Commission.
Authority 1 Date Enacted Date Updated	R.I.G.L § 39-1-27.7 2006 2010

Legislative and Regulatory Background

Rhode Island's sole investor-owned utility, Narragansett Electric (National Grid), administers and operates a portfolio of energy efficiency programs for its customers, which account for 99% of statewide sales of electricity. Recent legislation has significantly enhanced energy efficiency's role in planning and meeting resource needs. The Rhode Island legislature unanimously passed sweeping new legislation on June 23, 2006: the Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006 (R.I.G.L § 39-1-27.7). This act establishes a Least Cost Procurement mandate—requiring utilities to acquire all cost-effective energy efficiency with input and review from the Energy Efficiency and Resource Management Council (EERMC). Under the Least Cost Procurement mandate, National Grid is required to participate in strategic long-term planning and invest in all energy efficiency that is cost-effective and cheaper than supply on behalf of its customers.

The act also established requirements for strategic long-term planning and purchasing of least-cost supply and demand resources. Utilities must submit 3-year and annual energy efficiency procurement plans, which offer program details, as well as spending and savings goals. Hearings are held once a year before the Rhode Island Public Utilities Commission to review program plans. The current 3-year goals are 1.1% in 2009, 1.12% in 2010, and 1.36% in 2011.[40] The EERMC has proposed savings target of 1.7% in 2012, 2.1% in 2013, and 2.5% in 2014, which are currently being reviewed by the Commission.[41]

Rhode Island's EERS policy also includes natural gas targets. On November 1, 2010 National Grid proposed savings targets for 2011 of 173,379 MMBtu and spending goals of $10,715,000. Despite a 2010 legislative mandate to procure all cost-effective natural gas efficiency, the PUC also pointed to a legislative funding provision that it interpreted as setting a funding ceiling. As a result, the Commission approved natural gas efficiency savings for National Grid of 56,145 Annual MMBtu Savings in 2011 (~0.29% of sales).[42] The PUC has indicated that it will promptly reopen the proceeding if the legislative language in question is amended.[43] On May 18, 2011, the Rhode Island House passed legislation to clarify the full funding of all cost-effective natural gas efficiency. The Rhode Island Senate is expected to take up the legislation shortly. The EERMC has proposed savings target of 0.75% in 2012, 1.0% in 2013, and 1.2% in 2014, which are currently being reviewed by the Commission.

The EERMC has a specific legislative mandate and funding to guide, provide input, and oversee the development of 3-year energy efficiency procurement plans and related annual plans an consists of representatives of representing commercial, industrial, residential, low income, and environmental interests . The EERMC is also charged with completing an Energy Efficiency Opportunity Report to identify the size of the character of the cost-effective efficiency resources available in the state. The 3-year and annual energy efficiency procurement plans are developed by the utility with input and oversight of a subcommittee of the EERMC and other key stakeholders, including the Division of

[40] Docket No. 4116. February 8, 2010.(Revised Attachment B)
[41] See http://www.ripuc.org/eventsactions/docket/4202-EERMC-EST-Filing(9-1-10).pdf
[42] Docket 4209. January 21, 2011
[43] See ENE (Environment Northeast), *A Boost for Efficiency in Rhode Island*. Providence 2011; A bill is currently being considered: H 5281 would remove the cap on its natural gas energy efficiency charge and allow for a fully-reconciled funding mechanism.

Public Utilities and Carriers and TEC-RI, a consortium of the state's largest energy users. The full EERMC votes whether to approve the utility's EE plans before they are submitted to the PUC and is present in all related PUC dockets. The EERMC also is charged with evaluating the cost-effectiveness of the EE programs and upon a finding of cost-effectiveness, state laws provide for a fully reconciling funding mechanism to fund the EE program investments.

It is through Rhode Island's underlying economic procurement requirement, stakeholder involvement, and the subsequent PUC Efficiency Procurement Standards and dockets that an energy efficiency savings requirement is established for the electric utility.

Energy Savings Achieved vs. Targeted

National Grid, the state's electric and natural gas distribution utility has been able to meet the EE targets established through the above process. The utility plans to double the amount of savings for its customers, relative to 2008, over the three years from 2009 to 2011 through the implementation of programs that are lower than the cost of supply and are prudent and reliable. The projected cumulative amount of 265,000 net annual MWh savings over the three years is 90% of the "Aggressive Achievable Case" for energy efficiency procurement over the same period presented in an energy efficiency potential study by the consultancy KEMA submitted to the EERMC.[44] In its three-year plan, National Grid emphasized the importance of creating the delivery structure and financing mechanisms to enable the planned program expansion to proceed in a realistic and sustainable manner.[45] The program portfolio for 2011 is projected to have a benefit-cost ratio of 2.86. The Energy Efficiency Council has proposed savings target of 1.7% in 2012, 2.1% in 2013, and 2.5% in 2014, which are currently being reviewed by the Commission.

Table 12: Rhode Island Energy Efficiency Program Performance

	2008	2009	2010	2011
Annual Energy Savings Goal (MWh)	54,268	74,387	88,546	102,627
Goal as % of 2008 Sales	0.8%	1.1%	1.3%	1.5%
Annual Energy Savings Achieved (MWh)	60,053	81,000	NA	NA
Achieved Savings as % of 2008 Sales	0.9%	1.2%	NA	NA

Factors Affecting Performance

Funding Levels

In order achieve these levels of savings, funding increased from $24 million in 2009 to $31 million and $45.6 million in 2010 and 2011. The greater investments are required by Rhode Island's 2010 energy bill which requires full funding for all cost-effective efficiency measures. Funding sources include an energy efficiency program charge, revenue from carbon auction proceeds from the Regional Greenhouse Gas Initiative (RGGI), and the Forward Capacity Market. Investments in this three-year period will generate $281 million in lifetime energy savings for Rhode Island ratepayers.[46] Documented results for 2008-2010 show $345,128,000 in total benefits to electric ratepayers and $120,859,700 in total benefits to natural gas ratepayers. Total utility program cost for 2008-2010 was $66,328,600 for electric and $17,998,500 for natural gas.[47]

[44] See ENE (Environment Northeast), RI Opportunity Report and related information at, http://www.env-ne.org/resources/open/p/id/645/from/339
[45] National Grid Three Year Compliance Plan
[46] See: http://www.env-ne.org/public/resources/pdf/RI_EERMC_AnnualReport_April2011.pdf
[47] RI EERMC, Annual Report to the General Assembly, April 2011.

Least-Cost Procurement Policy

A key factor in Rhode Island's success has been the Least Cost Procurement requirement that the state's utility shall invest in efficiency resources whenever they are cost-effective and cheaper than supply resources. The establishment of the EERMC has also been critical in identifying the potential energy efficiency resource and acting as a guide and evaluator throughout the utility energy efficiency procurement planning process.

Decoupling and Performance Incentives

Rhode Island has also benefited from a newly established state law which removes barriers to investing in cost-effective energy efficiency, a policy known as "revenue decoupling," which breaks the link between a utility's retail electricity sales and revenues. Utilities also may recover the costs for running energy efficiency programs and earn incentives for high performance (ACEEE 2011).

Washington

Summary

Electric EERS	I-937 Energy Efficiency Biennial and Ten-Year Goals: Vary by Utility
Applicable Sector	Investor-owned utilities, Municipal utilities, Public Utility Districts, Co-operatives
Natural Gas EERS	None
Authority 1 Date Enacted	Ballot Initiative I-937 November 2006
Authority 2 Date Effective	WAC 480-109 11/28/07
Authority 3 Date Effective	WAC 194-37 4/18/08

Legislative and Regulatory Background

Washington voters approved ballot initiative 937 in November 2006 which set new renewable energy resource and conservation requirements for large electric utilities to meet. The ballot, codified in Chapter 19.285 RCW, had rules adopted for its implementation in 2007 and 2008.[48] The energy conservation section requires each qualifying utility (those with more than 25,000 customers in Washington) to "pursue all available conservation that is cost-effective, reliable and feasible." Seventeen utilities, both publicly owned and investor owned, currently meet the definition of qualifying utility. "High efficiency cogeneration" is included as part of conservation and the term is defined in the law. The law requires utilities to use the Northwest Power and Conservation Council's (NPCC) methodology to determine their achievable cost-effective conservation potential through 2019, and update that potential assessment every two years for the subsequent ten-year period. Utilities also must establish a biennial acquisition target for 2010-2011, and update that target every two years. If a utility does not meet its conservation goals, it must pay an administrative fine for each MWh of shortfall, starting at $50 and adjusting annually for inflation beginning in 2007.

The three major IOU's submitted reports in 2010 with a biennial conservation target as well as a ten-year achievable conservation potential. The energy efficiency targets Washington's utilities must meet amount to some of the most aggressive in the country. The credit for these ambitious targets is largely due to the law's requirement that utilities follow the NPCC methodology. The NPCC is the regional energy planning entity, established through the 1980 federal "Power Act." The Act codified energy efficiency as a real resource and required the region's largest supplier of electricity, the Bonneville Power Administration (BPA), to acquire energy efficiency that is cost effective, i.e., less expensive from the standpoint of the total cost per unit of energy saved than the next least-expensive

[48] WAC 480-109 for investor owned utilities; and WAC 194-37 for public utilities

available resource. To guide BPA, the Act authorized the NPCC to produce a Northwest energy efficiency and power plan every five years. In its Sixth Power and Conservation Plan released in 2010, the NPCC concludes that energy efficiency can meet 85% of load growth in the region through 2030 at an average cost of 3.6¢/kWh, providing over 5900 average MW (aMW) of new energy efficiency savings (NPCC 2010).[49] While the IOUs and public utilities did not all use the Power Plan to set targets, the document usefully informed the planning process.[50]

Prior to the implementation of its EERS, many of Washington's investor- and publicly-owned utilities had long records of significant investments in energy efficiency. Washington's diverse mix of private and public utilities have long records of offering customer energy efficiency and conservation programs.

Investor-owned utilities account for approximately half the retail electric sales in the state. Washington is a non-restructured state and has no public benefits funding to support programs. Investor-owned utilities recover the costs of energy efficiency programs through tariff riders. Program costs are reported and adjusted annually in proceedings before the Utilities and Transportation Commission.

Energy Savings Achieved vs. Targeted

Entering the second year of the biennial program planning period, Washington's IOUs are on track to meet their goals cost-effectively. Using the Total Resource Cost (TRC) test, PSE's 2010 electric and gas programs performed at 2.15 and 1.22, respectively (3.39 and 2.78 using the Utility Cost Test). The respective TRC figures for Avista in 2009 were 1.68 and 1.08.[51]

Table 13: Washington IOU Energy Savings Achieved vs. Targeted

Utility	2010-2011 Goal (MWh)	Biennial Target as % of 2009 Retail Sales*	2010 Achieved Savings** (MWh)
Avista[52]	128,603	2.4%	86,758
Pacificorp***[53]	74,460	1.8%	N/A
Puget Sound Energy[54]	622,000	2.8%	295,547

*Retail sales reported in EIA 2009
**Savings data reported in utility DSM Annual Business Plans/Report (PSE, Avista)
***Converted from Average MW

Factors Affecting Performance

Collaboration among Stakeholders

The extensive planning process undertaken in 2009 has paid dividends for program performance in 2010 and 2011. The planning process benefited from a Conservation Working Group (CWG), which created a forum for the three utilities and regional stakeholders to share best practices and lessons learned. The CWG was formed in 2011, primarily to aid in providing clarity, certainty, and consistency where possible for IOUs in implementing their I-937 requirements. No similar process exists for the public utilities.

[49] 5900 aMW equals 51,684 GWh. Taking Washington's share of electricity load in the Northwest (~51%), we have calculated the statewide goal in Washington to be 26,358 GWh by 2030, or 1.5% of 2009 retail sales annually.
[50] PSE used its own IRP to set its target; PacifiCorp looked at the 6th Plan and adjusted its "share" generally downwards based on its IRP and key differences between its service territory and the overall region; Avista used its share of the 6th Plan but added fuel switching. Some public utilities used the 5th Power Plan, which identified a lower amount of regional savings than the 6th Plan. Beginning with the next biennium—2012-2013—the 5th Power Plan will no longer be an option.
[51] Assumes 100% net-to-gross ratio
[52] UE-100176
[53] UE-100170
[54] UE-100177

Experience with Energy Efficiency

Washington's initial success staying on track to meet its targets may be partly attributed to the utility program delivery and reporting infrastructure established throughout the past decades, including a Regional Technical Forum that provides utilities with deemed savings for a host of EE measures. Washington's three IOUs have set annual DSM program portfolio savings targets for many years in IRPs, and BPA has required DSM reporting from the public utilities for years. The long-standing commitment to DSM in the region fostered numerous groups, systems, and tools that promote and deliver energy efficiency services. As a result, Washington achieved statewide savings of 0.61% compared to retail sales in 2008 (Molina et al. 2010).

EERS Impacts on an Established Energy Saver

The implementation of the I-937 targets benefits Washington more than if it had maintained the status-quo, however, sending an important lesson to states without a statewide EERS that have energy efficiency programs in place. Aside from spurring a slight ramp-up in savings levels, the statewide EERS provides the state's IOUs certainty that benefits program development. Importantly, the targets have a much greater impact driving higher levels of savings from public and co-operative utilities in Washington, which account for just over half the electric sales in the state and varied greatly in their DSM offerings in the past. Tacoma Power customers will see a major boost in energy efficiency investments as a result of I-937, for example. Most publicly-owned utilities in Washington, including Bonneville Power Administration, Seattle City Light, and Snohomish County Public Utility District, have historically provided funding for energy efficiency programs and services.

The targets also strengthened the system of evaluation, monitoring, and verification of energy efficiency savings from programs. Since the WUCT approves the biennial efficiency targets for investor-owned utilities, Commission staff must base their recommendation for approval on more sufficient evidence than the deemed savings previously submitted by utilities. The targets, therefore, is spurring a transition for some utilities to a system of third-party verified savings and measures installed, resulting in a statewide effort to improve and streamline reporting requirements. PSE, for instance, now relies primarily on third-party EM&V. The increased focus on EM&V will result in more certain savings and prudent energy efficiency investments.

Colorado

Summary

Electric Energy Efficiency Goals	PSCo and Black Hills Energy (BHE) both aim for 0.9% of sales in 2011 and increase to 1.35% (1.0% for BHE) of sales in 2015 and then 1.66% (1.2%) of sales in 2019
Applicable Sector	Investor-owned utilities
Natural Gas Goals	Expenditure targets equal to at least 0.5% of prior year's revenue—savings targets commensurate with spending targets and expressed in terms of gas saved per unit of program expenditure; goals set by gas utilities as part of their gas DSM program plans.
Authority 1	CRS 40-3.2-101, et seq.

Legislative and Regulatory Background

The Colorado legislature passed HB-07-1037 in April 2007, which amended Colorado statutes C.R.S. 40-1-102 and 40-3.2-101-105 by requiring the Colorado Public Utilities Commission (COPUC) to establish energy savings goals for investor-owned electric and gas utilities. The bill also requires the COPUC to provide utilities with financial incentives for implementing cost-effective energy-saving programs. The COPUC must report annually on the progress made by investor-owned natural gas and electric utilities in meeting their demand side management goals.

The EERS statute does not directly set a fixed schedule of statewide percentages of energy savings to be achieved by particular years, nor does it require the acquisition of all cost-effective energy efficiency resources. Instead it sets an overall multi-year statewide goal for investor-owned utilities of at least five percent of the utility's retail MWh energy sales in the base year (2006) to be met by the end of 2018, counting savings in 2018 and including savings from DSM measures installed starting in 2006. The law empowers COPUC to set interim goals for utilities and to modify goals.

Public Service Company Colorado (PSCo) and Black Hills Energy (BHE) together account for more than 80% of the total projected GWh savings and over 58% of retail electricity sales in the state; some municipal utilities and electric co-ops also implement efficiency programs.

In a May 2008 decision, the COPUC set energy savings goals for PSCo for the period 2009-2020. The goals set energy saving targets of 0.53% of retail sales in 2008, ramping up to 1% in 2015, and 1.2% in 2019. The savings would amount to 3,669 GWh over the 12-year period.[55] The Commission accepted modified goals for PSCo for 2009 and 2010 in a Settlement Agreement in Decision R08-1243 in February 2009, which were designed to save approximately 0.6% (176 GWh) in 2009 and 0.8% (237 GWh) in 2010, exceeding the mandated savings in both years.[56] PSCo plans to achieve 255 GWh in 2011.[57]

Black Hills Energy adopted an efficiency plan that aims to save 0.53% of projected sales in 2009 (10,287 MWh), 0.76% in 2010 (15,156 MWh), and 0.80% in 2011 (16,522 MWh).[58] The statutory minimum goal for Black Hills over the ten-year period is 93.9 GWh, based on 2006 sales.[59]

In May 2011, COPUC approved new goals for PSCo for the 2012-2020 period. The goals are approximately 130 percent of the annual goals approved in May 2008, beginning at 1.14% of sales in 2012, ramping up to 1.35% in 2015, and reaching 1.68% in 2020. The goals set out to achieve 3,984 GWh in the nine-year period.[60]

For investor-owned natural gas utilities, the EERS legislation structured the requirement in two parts. First, the natural gas IOU's must set DSM spending targets of more than 0.5% of revenues from customers in the prior year. Energy savings targets are then established by COPUC commensurate with spending and stated in terms of quantity of gas saved per dollar of efficiency program spending.

Energy Savings Achieved vs. Targeted

Leveraging parent company Xcel Energy's years of program delivery experience in Minnesota, PSCo surpassed their planned 2009 and 2010 electricity savings goals, saving 220 GWh in 2009 and 253 GWh in 2010.[61] Black Hills Energy was less successful in the 2009/2010 program period. BHE notes in its 2009/10 Annual Status Report that it received approval of its programs only a month prior to the July 1st, 2009 start date, which did not give the utility enough time to design and execute programs in time for the 2009 Summer. As a result, savings and spending fell below targets for the year. BHE spent $1.4 million and saved 4,554 MWh—58% and 44% of their respective targets.[62]

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[55] Docket No. 07A-420E, Decision C08-0560

[56] Based on 2009 retail sales. Xcel Energy/Public Service Company of Colorado 2009/2010 Demand-Side Management Biennial Plan, Electric and Natural Gas, Docket No. 08A-366EG. Originally filed August 2008, revised February 2009. In this profile, Xcel goals and savings are given at the generator level; these values need to be reduced by about 7% to get savings at the customer level.

[57] PSCo 2011 DSM Plan

[58] COPUC Docket No. 08A-518E Decision No. R09-0542,

[59] Public Utilities Commission Report to the Colorado General Assembly on Demand Side Management. April 28, 2009.

[60] *Docket No. 10A-554EG, Decision No. C11-0442*

[61] Docket No. 08A-366EG. 2009 Savings data from 2009 Demand-Side Management Annual Status Report, 4/5/10; 2010 Savings data from Fourth Quarter Colorado DSM Roundtable Update, 2/15/11.

[62] Black Hills Energy Colorado Electric Annual Status Report Energy Efficiency Programs 2009-2010

Table 14: Colorado Electric Utility Savings Targets as % of Sales

Utility	2009 Target	2009 Achieved	2010 Target	2010 Achieved	2011 Target	2020 (Cumulative 2012-2020)
PSCo	0.6%	**0.8%**	0.8%	**0.9%**	0.9%	13.75%
Black Hills Energy	0.53%	**0.23%***	0.76%	N/A	0.80%	

*Program year beginning July 1, 2009 ending June 30, 2010

For natural gas, PSCo had already budgeted 250% of the minimum spending requirement prior to the EERS, as gas prices had doubled due to suppliers building a pipeline out of the Rocky Mountains. Now that prices have declined again, energy efficiency measures are much less cost effective, many with a total resource cost of 1.1. In 2009, the first year goals took effect and the first year in which PSCo had a complete and comprehensive efficiency plan in place, savings were 308,761 Dth, or 97% of the goal the Commission-approved plan.[63]

Factors Affecting Performance

Funding Levels

One of primary ways utilities are using to achieve greater energy savings has been to invest more money: funding for utility energy efficiency has increased rapidly in Colorado as the PUC sets energy savings goals. According to the revised 2009/2010 Demand-Side Management Biennial Plan, PSCo increased their investment in gas and electric efficiency and demand programs from $63 million in 2009 to $80 million in 2010.

Performance Incentives

Policies complementary to the EERS partly attribute to PSCo's success. COPUC has implemented a performance-based incentive for PSCo, enabling them earn a return of 1-15% of net benefits on its demand-side management expenditures as long as it achieves at least 80% of its energy savings goal in any one year. The incentive is tied to energy savings achieved and the net economic benefits of the programs. The total payment of the performance incentive and a separate pre-tax disincentive is capped at $30 million. Black Hills Energy has adopted the same mechanism.

Meeting Future Goals

With the aggressive savings increases planned over the next three to four years, PSCo will build on its strong residential, commercial and industrial programs, expanding marketing and incentive levels, and possibly adding further market transformation programs. In addition to continuing and expanding existing programs, new directions will be explored, including behavioral programs in the residential sector.

Illinois

Summary

Electric EERS	0.2% annual savings in 2008, ramping up to 1% in 2012, 2% in 2015 and thereafter
Applicable Sector	Investor-owned utilities; retail supplier; Illinois DCEO
Natural Gas EERS	8.5% cumulative savings by 2020 (0.2% annual savings in 2011, ramping up to 1.5% in 2019)
Authority 1	§ 220 ILCS 5/8-103
Authority 2	Public Act 96-0033
Authority 3	S.B. 1918

[63] Docket No. 08A-366EG. 2009 Demand-Side Management Annual Status Report, 4/5/10

Legislative Background

The scope of energy efficiency activity in Illinois began a dramatic expansion in July 2007, when the state legislature passed the Illinois Power Agency Act (IPAA), which includes requirements for energy efficiency and demand response programs. The IPAA establishes an EERS that sets incremental annual electric and natural gas savings targets based on previous year's consumption, beginning on June 1 of that year. The electric savings requirements began at 0.2% in 2008 and ramps up to a requirement of 2% annual savings in 2015 and thereafter. The natural gas goals begin in 2012 with a 0.2% reduction of 2011 sales and ramp up to 1.5% annual savings by 2019.

Table 15: Illinois Electric EERS Savings Goals

2008	2009	2010	2011	2012	2013	2014	2015+
0.20%	0.40%	0.60%	0.80%	1.00%	1.40%	1.80%	2.00%

Investor-owned electric utilities are responsible for roughly 75% of program savings and spending, while the Illinois Department of Commerce and Economic Opportunity (DCEO) administers the remaining 25% of the funds, which are used to for efficiency programs serving government facilities, low-income households, and market transformation-oriented information and training programs.

The rate increase for customers due to energy efficiency is limited by statue to 0.5% of the total 'per kWh' charge in the first year and increasing to 2.0% in 2012. If the rate impact cap is reached, the energy savings goals will be relaxed to the maximum savings that can be achieved within the rate impact cap. If, after 2 years, an electric utility fails to meet the efficiency standard it must make a contribution to the Low-Income Home Energy Assistance Program and transfer the program to the Illinois Power Authority.

Energy Savings Achieved vs. Targeted

Results to date among the major program administrators in Illinois have been mixed. ComEd and Ameren Illinois exceeded savings requirements in its first two program years while DCEO has not met savings goals in either of its first two program years. Independent analysis of ComEd's programs in its second program year found portfolio cost-effectiveness based on the Illinois Total Resource Cost (TRC) test to be 2.84. Ameren Illinois met its goals in 2009 cost-effectively as well as its portfolio scored a 2.78 using a TRC Test.

Table 16: Illinois Electric Efficiency Savings 2008-2010

Utility	2008-2009 (PY 1) Requirement (MWh)	2009 Achieved (MWh)	Percent Attained	2009-2010 (PY 2) Requirement (MWh)	2010 Achieved (MWh)	Percent Attained
ComEd	148,842	**163,717**	110%	315,223	**456,151**	145%
Ameren Illinois	62,808	**89,955**	143%	118,288	**142,995**	121%
DCEO	54,572	**27,285**	50%	110,715	**72,331**	65%

Sources: ComEd Year 1 Evaluation Report; ComEd Year 2 Evaluation Report; Ameren Illinois Year 1 Annual Report; Ameren Illinois Final PY2 Monthly Report September 2010; DCEO Program Year 2 Evaluation

Factors Affecting Performance

DCEO claims numerous factors prevented outright success for its public sector and low-income programs, such as the economic downturn and its effect on government and school budgets. DCEO market transformation activities such as training for contractors and technical assistance do not count for any savings during the first three years and public entities also require substantial technical assistance with completing paperwork, which increases the administrative costs of running the programs. Federal funds from the Recovery Act used by municipalities also supplanted, rather than supplemented, the state government programs, impeding higher levels of savings. In response to these challenges, DCEO adopted new approaches in more recent program years, hiring more contractors to assist government agency customers, and partnering directly with Community Colleges and the State Board of Education to promote DCEO energy efficiency programs. DCEO also partnered with Regional Planning Agencies, which were assisting the administration of municipal-aimed Recovery Act funds (Energy Efficiency Community Block Grants (EECBG)).

Funding Levels

In order to meet the increasing savings goals, Illinois utilities increased energy efficiency budgets. Funding for electric efficiency programs shot up from less than one million in 2007 to $89.9 million in 2009 and then to $107.4 million for 2010 (ACEEE 2011). Natural gas efficiency budgets went from zero in 2007 to over $4 million in 2009. In its 2008-2010 plan, ComEd's spending screens ramp up from $39.4 million to $126.7 million in 2010. In its 2011-2013 plan, its spending screens stabilize around $160 million per year. For Ameren Illinois the limit levels off at $60 million. However, a process is underway in which the Commission will report to the legislature on the impact of the spending caps, and the legislature will have an opportunity to increase or eliminate those caps.

Meeting Future Goals

There is widespread concern among program administrators that when the spending caps are reached, the annual savings goals will not be met. The spending limit stays fixed after it reaches 2% in 2012, but the MWh requirements continue to increase. In the long term, all the program administrators agree that new funding will be required and that there will be an effort to raise the spending limits supported by environmental and consumer stakeholders, who assert that annual savings above 1% can be reached and sustained cost-effectively statewide.

Minnesota

Summary

Electric EERS	1.5% annual savings beginning in 2010 (1% from programs, 0.5% from codes, standards, transmission and generation improvements).
Applicable Sector	Investor-owned utilities; retail suppliers
Natural Gas EERS	0.75% annual savings from 2010-2012; 1.5% annual savings in 2013
Authority 1 Date Enacted Date Effective	Minn. Stat. § 216B.241 2/22/2007 2/22/2007

Legislative Background

Minnesota investor-owned electric and gas utilities are subject to the energy savings requirements of the Next Generation Energy Act (NGEA), passed by the Minnesota Legislature in 2007 (Minnesota Statutes 2008 § 216B.241). Among its provisions, the Act set energy-saving goals for utilities of 1.5% of retail sales each year, commencing with the first triennial plan period that began January 1, 2010. Of the 1.5%, the first 1% must be met with direct energy efficiency energy savings, or conservation improvements. This may include savings from efficiency measures installed at a utility's own facilities. The NGEA also allows savings to be achieved indirectly through energy codes and appliance standards. Up to 0.5% may be met by efficiency enhancements to each utility's generation, transmission, and distribution infrastructure. Electric and natural gas municipal utilities and co-operatives must set energy efficiency spending goals based on a percentage of revenue. Prior to the Next Generation Energy Act going into effect fully in 2010, Minnesota utilities were required to spend a percentage of gross operating revenue (0.5% gas, 1.5% electric) on energy efficiency programs rather than to achieve a set amount of energy savings.

The NGEA allows a utility to request a lower target (based on historical experience, an energy conservation potential study, and other factors), but in no case can that be lower than 1% per year. Lower savings can also be justified if the Commissioner of Commerce determines that additional savings are not cost-effective to ratepayers, the utility, participants, and society. In 2009, the state legislature amended the Act to reduce the mandated level of savings during the first three years for natural gas utilities, establishing an interim average annual savings goal of 0.75 percent over 2010-2012 (Minnesota Session Laws 2009, Ch. 110, Sec. 32).

For the first triennial period 2010-2012, CenterPoint Energy's natural gas energy efficiency plan is to increase savings from 0.73 to 0.78%, averaging the minimum 0.75%. Xcel Energy electric savings goals included in their approved triennial plan are 1.15% in 2010, 1.2% in 2011, and 1.3% in 2012.[64]

Energy Savings Achieved vs. Targeted

Minnesota's utilities achieved increasing levels of efficiency savings over the 2007-2009 period. The Minnesota Office of Energy Security (OES) reported that statewide energy savings in 2009 met around 1.0 percent and 0.6 percent, electric and natural gas respectively, of 2007-2008 retail sales.

Table 17: Minnesota Statewide Electric Savings Achieved from Conservation Improvement Programs, 2006-2009

Year	Statewide Electric Savings Achieved (MWh)	Savings as % of 2007 Sales	IOU Natural Gas Savings (MCF)	Savings as % of Average Sales[65]
2006	411,999	0.60%	N/A	N/A
2007	468,070	0.68%	N/A	N/A
2008	597,288	0.87%	1,534,121	0.54%
2009	648,163	0.95%	1,777,369	0.63%

Source: Minnesota Conservation Improvement Program Energy and Carbon Dioxide Savings Report for 2008-2009, March 23, 2011

Factors Affecting Performance

Funding Levels

Reaching these higher levels of savings necessitated increased funding levels. The $144 million statewide budget for electric efficiency programs in 2009 eclipsed 2008 levels by $42 million. Spending levels will continue to rise as goals ramp-up and programs attempt to reach new sectors and achieve deeper levels of savings. Overall Conservation Improvement Program (CIP) spending by investor-owned utilities is projected to increase from $77 million in 2008 to $127 million in 2010, an increase of 65 percent.

Performance Incentives

In 2010, Minnesota adopted a new "shared savings" model for incentives. This incentive is voluntary (utilities are not required to participate), applies to any utility participating in the Conservation Improvement Program, and will replace existing incentives in 2010.[66] This incentive is designed to help utilities meet the 1.5% savings goal. The percentages are set individually for each utility and are reviewed each year.

[64] Targets presented in: CenterPoint Energy's 2010-2012 Triennial Conservation Improvement Program Plan, Xcel Energy 2010/2011/2012 Triennial Plan Minnesota Electric and Natural Gas Conservation Improvement Program
[65] Based on "average sales" figures presented in CIP Energy and Carbon Dioxide Savings Report for 2007-2008.
[66] Order issued January 27, 2010 in Docket E,G-999/CI-08-133

Experience with Energy Efficiency

Minnesota has a long record of customer energy efficiency programs offered by both investor-owned and publicly-owned utilities. These programs have achieved significant energy savings for well over two decades, without any of the interruption or upheavals that occurred in most other states that restructured their electric utility industries.

Meeting Future Goals

Despite higher spending levels, Minnesota will face several challenges as its utilities attempt to find ways to meet future savings goals. In the case of Xcel Energy, it will strive to meet the electric 1.5% goal over the long term from customer programs, possibly during the next triennial planning period from 2013 to 2015. While some stakeholders in the state argue the goal cannot be achieved over the long-term, others believe that the Minnesota's success thus far doubling and tripling energy savings as utilities ramp up demonstrates the feasibility of aggressive savings in the state.

Impact of Codes and Standards

The impact of higher appliance standards and building codes on utility savings may be a major factor determining the future savings levels for Minnesota utilities, depending on how the Commission addresses the issue in future dockets. Stringent codes and standards that raise baseline conditions for energy efficient equipment result in lower savings attributable to utility efficiency programs, which can reduce a utility's ability to claim savings and reduce the cost effectiveness of program portfolios. Mitigating these effects, Minnesota is one of the few states that permit utilities to get credit for savings from codes and standards.

Collaboration among Stakeholders

Xcel Energy describes their future efficiency program success as dependent on many factors, including the growth of their existing program portfolio, emerging energy efficient equipment technologies, market transformation, and the development of methodologies to quantify savings from nontraditional programs. Two key energy savings areas Xcel is looking at that fit squarely with the 1.5% Energy Efficiency Solutions Project are behavioral programs and codes and standards.

Seeking to address the issue of codes and standards among other potential barriers, the Minnesota Office of Energy Security contracted with the Minnesota Environmental Initiative (MEI) to lead a multi-stakeholder process to find ways to achieve the 1.5% goal. The MEI developed a "1.5% Energy Efficiency Solutions Project" and convened technical working groups to focus on four "policy barrier issue areas": behavioral programs, low income, codes and standards, and utility infrastructure improvements. The Project released its final report in March 2011.[67]

North Carolina

Summary

Electric EERS	Renewable Energy and Energy Efficiency Portfolio Standard (REPS). Investor-owned: 12.5% by 2021 and thereafter. Municipal and co-operative utilities: 10% by 2018. Energy efficiency is capped at 25% of the 2012-2018 targets and at 40% of the 2021 target.
Applicable Sector	Investor-owned utilities, Municipal utilities, Co-operatives
Natural Gas EERS	None
Authority 1 Date Enacted	N.C. Gen. Stat. § 62-133.8 Enacted 8/20/2007 Effective: 1/1/2008

[67] http://mn-ei.org/projects/images/EE1.5/Report/1.5EESolutionsFinalReportwithoutAppendices.pdf

Authority 2	04 NCAC 11 R08-64, et seq.
Date Enacted	2/29/2008
Date Effective	2/29/2008

Legislative Background

North Carolina Senate Bill 3 was finalized in 2008, introducing the state's combined Renewable Energy and Energy Efficiency Portfolio Standard (REPS). Under the REPS, public electric utilities in the state must obtain renewable energy power and energy efficiency savings of 3% of prior-year electricity sales in 2012, 6% in 2015, 10% in 2018, and 12.5% in 2021 and thereafter. For IOUs, energy efficiency is capped at 25% of the 2012-2018 targets and at 40% of the 2021 target. Co-operative and municipal utilities may satisfy their all of their REPS requirements with energy efficiency outside of particular set-asides for solar and other resources. Utilities demonstrate compliance by procuring renewable energy credits (RECs) earned after January 1, 2008. Under NCUC rules, a REC is equivalent to 1 MWh of electricity avoided through an efficiency measure. Since the REPS goals are cumulative, the 12.5% target in 2021 will require 5% of its sales in 2021 to be met with energy efficiency *over the entire 13-year period* in which energy efficiency savings may be counted. Averaged over three years, each target period until 2018 requires annual savings of 0.25%. The final period from 2018 to 2020 will allow annual energy savings of 0.83%. Utilities plan to employ more than the full quarter allowable over the next ten years. Industrial customers may opt-out of utility energy efficiency programs and not bear the costs of new programs if they implement their own programs.

Table 18: REPS Savings Schedule and Eligible Efficiency for North Carolina IOUs

Year	Cumulative Renewables Requirement (% of Sales)	EE Allowed (Total Annual) (% of Sales)
2012	3.00%	0.75%
2015	6.00%	1.50%
2018	10.00%	2.50%
2021	12.5%	5%

Each electric power supplier must file a REPS compliance plan for Commission review as part of its Integrated Resource Planning (IRP) filing on or before September 1 of each year. A utility's IRP filing must include a comprehensive analysis of all resource options considered by the utility, including demand-side management and energy efficiency, which must result in "the least cost mix of generation and demand reduction measures achievable..."[68] According to Commission Rule R8-60, IRP filings must include a 15-year forecast of demand-side resources, among other requirements for the assessment and characterization of the demand-side resource.

EERS Impact on Energy Efficiency Programs

The targets have been effective in prompting utilities to develop energy efficiency programs, bringing substantial benefits to customers. Duke Energy Carolinas introduced energy efficiency programs in mid-2009 and projects savings from these programs will achieve more energy efficiency savings than can be utilized under the REPS for the foreseeable future.[69] Progress Energy had existing programs prior to Senate Bill 3, but developed an expanded portfolio of programs between 2008 and 2010.[70] Duke and Progress estimate cumulative savings to be 4.9% and 6.2% of retail sales, respectively, over the next ten years. Dominion North Carolina Power plans to achieve energy efficiency savings

[68] N.C. Gen. Stat. § 62-2(3a)
[69] Duke IRP, page 16
[70] Progress Energy IRP

beginning in 2011.[71] *As these targets are adjusted annually, the next couple of years will be critical as* Duke in particular shifts from a program portfolio that emphasizes CFLs towards a more diverse portfolio. As of the writing of the report, no public information is available detailing actual energy savings from energy efficiency programs.

The REPS goals succeeded in pushing North Carolina's utilities to develop programs, with the added benefit of catalyzing programs in South Carolina. While the targets are some of the lowest in the nation, utilities may set savings targets above the allowable REPS goal. In some instances however, *such as with Dominion Power, utilities will only seek to save the minimum necessary to meet the* REPS goal.

Complementary to the REPS goals, PEC and Duke have also obtained financial structures that promote added achievement.[72] The initial results suggest that Duke has been very aggressive in making sure it achieves as much as possible early in its program deployment. Longer term impacts are less clear. PEC has been less forthcoming about its program impacts and it is not clear that financial structures alone are enough to motivate PEC. It is also unclear whether recently approved lost revenue adjustment mechanisms approved for both utilities will persuade the companies to invest more heavily in demand resources than supply, namely nuclear power, resources.[73]

While prompting utilities to develop energy efficiency program portfolios is a notable achievement, particularly for public and co-operative utilities unlikely to pursue DSM without a policy in place, the paltry 5% cumulative goal energy efficiency goal will not drive annual efficiency savings levels much higher than 0.40% over the next decade—acting more like a business-as-usual baseline than a goal to drive market development and transformation. There is ongoing disagreement among environmental groups and utilities over whether the energy efficiency programs proposed by the IOUs in their latest resource plans are fully harnessing the energy efficiency resource.[74] Adding additional uncertainty to the situation in North Carolina, the N.C. State Legislature also has a bill under consideration that would repeal Senate Bill 3.[75]

Maryland

Summary

Energy Efficiency Goal	15% per-capita electricity use reduction goal by 2015 with targeted reductions of 5% by 2011 calculated against a 2007 baseline (10% by utilities, 5% achieved independently)
Applicable Sector	Statewide Goal
Natural Gas EERS	None
Authority 1 Date Enacted: Date Effective	Md. Public Utility Companies Code § 7-211 04/24/2008 06/01/2008

Legislative Background

Although Maryland's utilities ran energy efficiency and demand response programs in the 1980s and early 1990s, most of these efforts were discontinued when the state removed regulations during utility restructuring in the late 1990s. The EmPOWER Maryland Energy Efficiency Act of 2008 directs the Maryland Public Service Commission (PSC) to require electric utilities in the state to provide energy efficiency services to its customers to achieve 10% of the 15% per-capita electricity use reduction goal by 2015 with targeted reductions of 5% by 2011 calculated against a 2007 baseline (Order 82344). The 15% goal is equivalent to approximately 11,206 GWh, or 17% of 2007 retail sales.[76] The Maryland Energy Administration (MEA) and other public and private stakeholders, including the

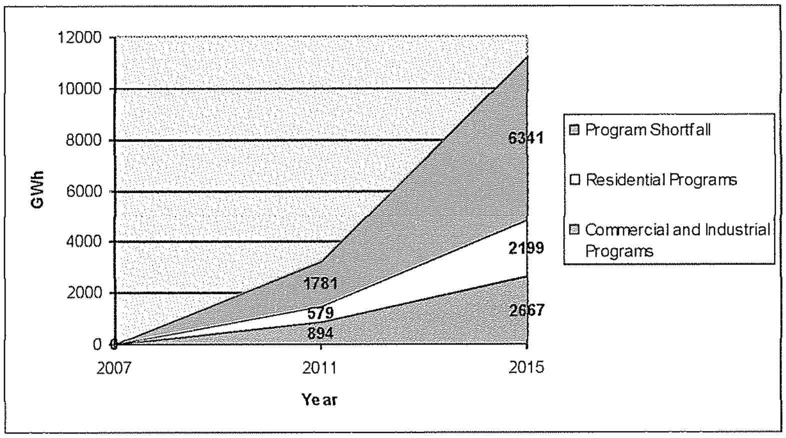
[71] Dominion IRP
[72] Progress: Docket E-2, sub 931; Duke: Docket E-7 sub 831
[73] John Wilson, SACE. Personal e-mail 3/10/11
[74] SACE Comments on Duke and PEC IRP
[75] House Bill 431
[76] Maryland Energy Administration. 2010. Maryland Energy Outlook.

Department of Housing and Community Development (which runs the weatherization program and Department of General Services (runs the public-sector Energy Savings Performance Contracting program) are responsible for achieving the remaining 5% of the overall 2015 electricity savings target. Utility programs must also achieve a reduction in per capita peak demand of at least 5% by end of 2011, 10% by 2013, and 15% by 2015.

Regulatory Background

In late 2008, Maryland's utilities filed energy efficiency and demand reduction plans to achieve the EmPOWER Maryland goals. The "interim" energy efficiency savings goals set in the plans are not sufficient to meet the 2011 or 2015 EmPOWER Maryland goals.[77] Maryland's two largest utilities, Baltimore Gas and Electric (BGE) and Potomac Electric Power Company (PEPCO) set interim goals that fall 40% and 30% short of the EmPOWER Maryland goals for 2015. MEA plans to save 73 GWh for programs in FY11, ramping up from the 64 GWh it saved between 2009 and 2010.[78] As of the end of December 2010, MEA was achieving 97 GWh.[79]

Figure 4: Projected Energy Efficiency Savings from Approved 2008 EmPOWER Maryland Plans



Source: Maryland Energy Administration, 2010

In its 2010 Energy Outlook report, the MEA projects that its programs combined with the approved PSC programs would reduce statewide energy consumption by approximately 4,866 GWh by 2015, which is less than half the overall goal of 11,206 GWh. Nonetheless, this projection would result in around 7% cumulative savings by 2015, or an average of about 1% annual savings, a significant achievement.

Energy Savings Achieved vs. Targeted

The latest DSM reports submitted by Maryland's major IOUs show that while programs are ramping up savings, they have not met their interim goals and will meet neither the interim goals nor the EmPOWER Maryland goals in 2011. The table below outlines the interim targets forecasted by utilities in their 2008 plans, reported savings, and how they compare to the 2011 EmPOWER Maryland Goal.[80]

[77] Allegheny Power: Case 9153, Baltimore Gas & Electric: Case 9154, Potomac Electric Power Company (PEPCO): Case 9155; Delmarva Power & Light: Case 9156; Southern Maryland Electric Cooperative (SMECO): Case 9157

[78] Maryland Energy Administration, EmPOWERing Maryland Clean Energy Programs FY 2011

[79] Walt Auburn, Maryland Energy Administration. Personal Conversation. May 17, 2011.

[80] Yearly numbers are taken from the Full Year tables of each Annual Report and the Program to Date numbers are taken from the 2010 Annual report. The yearly summations for each utility will not equal the respective program to date numbers due to reporting issues or corrections.

Table 19: EmPOWER Maryland Utilties Savings Targets vs. Achieved

Utility		2009 Interim Target (MWh)	2010 Interim Target (MWh)	2011 Interim Target (MWh)	2009-2011 Total Target	2009-2011 EmPOWER Maryland Goal
Allegheny Power	Forecasted	6,757	27,201	46,119	109,955	122,664
	Reported	66	15,068	N/A	32,673	32,673
	Difference	-99%	-45%		-70%	-73%
BGE	*Forecasted*	*295,285*	*351,735*	*412,096*	*1,059,116*	2,052,948
	Reported	97,209	274,068	N/A	371,277	371,277
	Difference	-42%	-22%		-65%	-83%
Delmarva Power & Light	Forecasted	34,036	37,321	77,931	149,288	503,202
	Reported	11,035	11,706	N/A	22,925	22,925
	Difference	-68%	-69%		-85%	-96%
Pepco	Forecasted	145,141	163,800	279,687	588,628	1,874,656
	Reported	*38,340*	*68,149*	*N/A*	*106,489*	*106,489*
	Difference	-74%	-58%		-82%	-94%
SMECO	Forecasted	24,325	30,923	27,350	82,598	254,827
	Reported	248	18,461	N/A	18,494	18,494
	Difference	-99%	-40%		-78%	-95%
Total	**Forecasted**	**543,884**	**679,129**	**843,183**	**2,096,074**	**4,914,786**
	Reported	**146,898**	**387,452**	N/A	**551,858**	**551,858**
	Difference	**-73%**	**-43%**		**-74%**	**-89%**

Source: Maryland Public Service Commission, Annual 2010 EmPOWER Maryland Overall Implementation & EM&V Progress Report, March 22, 2011

Factors Affecting Performance

A recent report from the Maryland Public Interest Research Group (PIRG) issued a detailed account of how Maryland is falling behind on its energy efficiency goals (Maryland PIRG 2011). The report places much of the blame on the PSC for failing to properly initiate and oversee the EmPOWER Maryland initiative. The PSC delayed implementation of the EmPOWER Maryland programs; restricted the types of programs it allows utilities to pursue, namely through its cost-effectiveness test; and did not hold utilities accountable for electricity savings shortfalls. The report also notes that non-utility programs have been weakened because of decreased funding from sources intended for energy efficiency programs. Maryland participates in the Regional Greenhouse Gas Initiative (RGGI), which has brought more than $148 million to the state's Strategic Energy Investment Fund since 1998, nearly half of which was originally allocated for energy efficiency. In 2010, the Governor and General Assembly cut this to 20 percent and diverted funds to assist utility customers pay bills. A similar proposal is in place for 2011 through FY 2014.

While the PIRG report rightly discusses the failure of the PSC, it should be noted that Maryland's utilities faltered in the planning and execution of energy efficiency programs. The utilities lack staff with programmatic experience and failed to exhaust the full range of potential energy efficiency measures in their initial plans. Additionally, while the scale of its effects is hotly debated, there is little doubt that the weakened economy played some role in the lower than expected customer participation rates.

Moving forward, the Maryland PSC commissioned EM&V reports for the completed program period, which should instruct utilities on how to improve upon programs. As Maryland attempts to get on track, the lesson that can be drawn from the past four years is that while aggressive goals send clear signals the future robustness of energy efficiency programs, it must be met with sustained commitment and aligned processes from Commissions and utilities.

Michigan

Summary

Electric EERS	0.3% annual savings in 2009, ramping up to 1% in 2012 and thereafter
Applicable Sector	Investor-owned utilities, co-operatives, municipals
Natural Gas EERS	0.10% annual savings in 2009, ramping up to 0.75% in 2012 and thereafter
Authority 1	Act 295 of 2008
Date Effective	10/6/2008

Legislative Background

Michigan adopted an EERS in October 2008, when the Clean, Efficient, and Renewable Energy Act was signed into law, requiring all types of electric and natural gas utilities to provide "Energy Optimization (EO) Programs." Michigan's EERS requires electric utilities to achieve 0.3% savings in 2009; 0.5% in 2010; 0.75% in 2011; and 1.0% in 2012 and each year thereafter. Percentages are savings relative to the prior year's total retail electricity sales. Natural gas utilities must achieve 0.1% savings in 2009; 0.25% in 2010; 0.5% in 2011; and 0.75% in 2012 and each year thereafter. Percentages are of the prior year's total annual retail natural gas sales in decatherms or equivalent MCFs.

Table 20: Michigan Electric and Natural Gas Energy Efficiency Savings Targets

		2009	2010	2011	2012
Electric	Percent Savings	0.30%	0.50%	0.75%	0.75%
	Savings (MWh)	326,056	502,797	742,451	N/A
Natural Gas	Percent Savings	0.10%	0.25%	0.50%	0.75%
	Savings (Mcf)	551,931	1,370,282	2,489,179	N/A

Source: Michigan PSC, Report on the Implementation of P.A. 295 Utility Energy Optimization Programs, January 2011

Regulated investor-owned utilities are responsible for 88.9 percent of the statewide electric savings targets; municipal utilities represent 7.8 percent of savings; and electric cooperatives, 3.4 percent. Most efficiency programs are administered by the utilities, although some have opted to fund a state-selected program administrator, Efficiency United, through an alternative compliance payment. Although Efficiency United program services are not subject to the statutory savings targets, equivalent contractual targets were imposed by the Commission. Large electric customers, as determined by their peak use, may administer their own programs.

The 66 utilities that did not opt to pay the alternative compliance payment must propose Energy Optimization (EO) Plans to the Michigan Public Service Commission (MPSC). There are limits to how much each utility many collect and spend on energy efficiency programs. In 2011, that spending cap is 1.5% of total retail sales revenues for 2009. In 2012 and thereafter, the spending cap is 2.0% of the total retail sales revenues for the two years preceding.

Energy Savings Achieved vs. Targeted

Overall, Michigan EO program savings for electric and natural gas achieved 129 percent of the statewide target in 2009. IOUs achieved 130 percent of their savings target, while municipal utilities reached 107 percent of their savings targets and electric cooperatives met 17 percent of their target (MPSC 2011). The Commission recently approved EO plans from Detroit Edison and Consumers Energy in which both utilities plan to exceed electric and natural gas savings targets every year through 2015.[81]

Table 21: Michigan Energy Efficiency Savings vs. Targeted

	2009 Requirement (MWh)	2009 Achieved (MWh)	Percent Attained	2010 Requirement (MWh)	2011 Requirement (MWh)
Statewide Electric EO Program Savings	326,056	375,652	129%	502,797	742,451

Factors Affecting Performance

Funding Levels

A major ramp-up in program funding has been critical to the success of EO programs thus far. Aggregate statewide funding (electric and natural gas) for EO programs was $89 million in 2009. Budgets for 2010 and 2011 are $137 million and $191 million, respectively.

Collaboration among Stakeholders

Michigan utilities benefited from a coordinated approach that included a statewide Energy Optimization Collaborative with the mandatory participation of all gas and electric providers. The Collaborative, which also included energy efficiency experts, energy professionals, and other stakeholders, reviewed and improved Energy Optimization plans to maximize their effectiveness. Michigan's utilities quickly planned, designed and launched programs only months after the approval of their EO plans. While the initial programmatic focus was on lighting and other "low-hanging fruit," the major utilities plan to broaden their focus and reach new customers in the commercial and industrial sectors in order to achieve deeper savings.

Decoupling and Performance Incentives

Complementary policies such as revenue decoupling and performance incentives have also improved the business model for utility investments in energy efficiency. The Commission has approved revenue decoupling for Consumers Energy and Detroit Edison as well as for a number of gas utilities. The Commission also permits Detroit Edison to receive a performance incentive for exceeding their annual energy savings target. Performance incentives cannot exceed 15% of the total cost of the energy efficiency programs (MPSC 2011).

New Mexico

Summary

Electric EERS	Energy Efficiency Resource Standard: 5% reduction from 2005 total retail electricity sales by 2014, and a 10% reduction by 2020
Applicable Sector	Investor-owned electric utilities
Natural Gas EERS	None
Authority 1	N.M. Stat. § 62-17-1 et seq.

[81] DTE: U-15806-EO Amended; MichCon. U-16412 Amended December 2010

Legislative and Regulatory Background

In 2008, New Mexico adopted an amended version of the Efficient Use of Energy Act which: (1) directs utilities to develop and implement cost-effective DSM programs, (2) defines "cost-effectiveness" in terms of the total resource cost test, (3) establishes cost recovery mechanisms for both electric and natural gas utilities, (4) directs the New Mexico Public Regulation Commission to establish rules for integrated resource planning, and (5) directs the Commission to remove financial disincentives for utilities to reduce customer energy use through DSM programs. On February 27, 2008, Governor Bill Richardson signed House Bill 305 into law, amending the Efficient Use of Energy Act to establish energy efficiency targets for the state. Investor-owned utilities are now required to achieve a 5% reduction from 2005 total retail electricity sales by 2014, and a 10% reduction by 2020. A utility that determines it cannot achieve the energy saving requirements shall report to the Commission, explain the shortfall, and propose alternative requirements based on acquiring all cost-effective and achievable energy efficiency and load management resources. If the commission determines that the requirements exceed the achievable amount of energy efficiency and load management available, it may establish lower requirements for the utility.

Distribution cooperative utilities, which are not fully regulated by the PRC, must annually consider self-imposed electricity reduction targets and design demand side management programs to enable them to meet those targets. Each cooperative utility must submit a report to the PRC annually describing their demand side management efforts from the previous year (DSIRE).

Energy Savings Achieved vs. Targeted

Since the adoption of an EERS, New Mexico's investor-owned utilities have developed programs for all customer segments. The electric IOUs suggest in their latest round of reporting that most, if not all, anticipate reaching the 5% cumulative goal by 2014. Experience thus far indicates that utilities can meet goals cost-effectively. In 2009 and 2010, PNM's program portfolio as measured by the Total Resource Cost test was 1.56 and 2.22, respectively. The average cost per kWh of lifetime energy savings from the energy efficiency programs PNM implemented in 2009 and 2010 was 1.76 cents and 1.89 cents, respectively. The latest approved portfolios of programs demonstrate that utilities are learning important lessons on program delivery strategy and customer participation rates, which has led to the expansion and refinement of numerous programs in the last planning period.

Table 22: New Mexico Energy Savings Achieved and Targeted

Year	New Mexico IOU Achieved and Projected Savings 2008-2014 (MWh)		
	PNM	SPS	El Paso Electric
2008	35,200 (includes DR)*	1,279*	855*
2009	39,900*	13,964*	4,667*
2010	58,900*	28,908**	9,474**
2011	58,489	32,436	25,437
2012	69,920	36,979	30,691
2013	79,733	36,979	30,691
2014	77,605***	36,979	30,691
2014 Cumulative Savings (Goal)	**411,000 (411,000)**	**187,689 (187,689)**	**116,025 (75,000)**

* Verified savings
** Estimated savings
***PNM Goals only projected out to 2013. 2014 figure what would be needed to meet 5% goal.

Sources:
PNM: For 2008, see Docket No. 10-00078-UT; 2009 and 2010 savings figures from Energy Efficiency Annual Reports; For 2010-2013 Plan, See PNM 2010 DSM Plan (Docket 10-00280-UT)
SPS: 2010/11 Energy Efficiency and Load Management Plan (Docket 09-00352-UT)
El Paso Electric: Energy Efficiency and Load Management Plan for 2011 (Docket 10-00047-UT)

Factors Affecting Performance

Decoupling and Performance Incentives

The New Mexico PRC adopted rules concerning disincentive removal and performance-based incentives in May 2010. The rules specify amounts the utilities are allowed to collect per kWh and peak KW of verified savings, in addition to program cost recovery. However, the amounts specified in the rules are in the process of being modified utility-by-utility in DSM program plan review dockets subsequent to issuance of the rules. The provision of these disincentive/incentive adders is expected to motivate the utilities to increase DSM budgets and energy savings targets.

New York

Summary

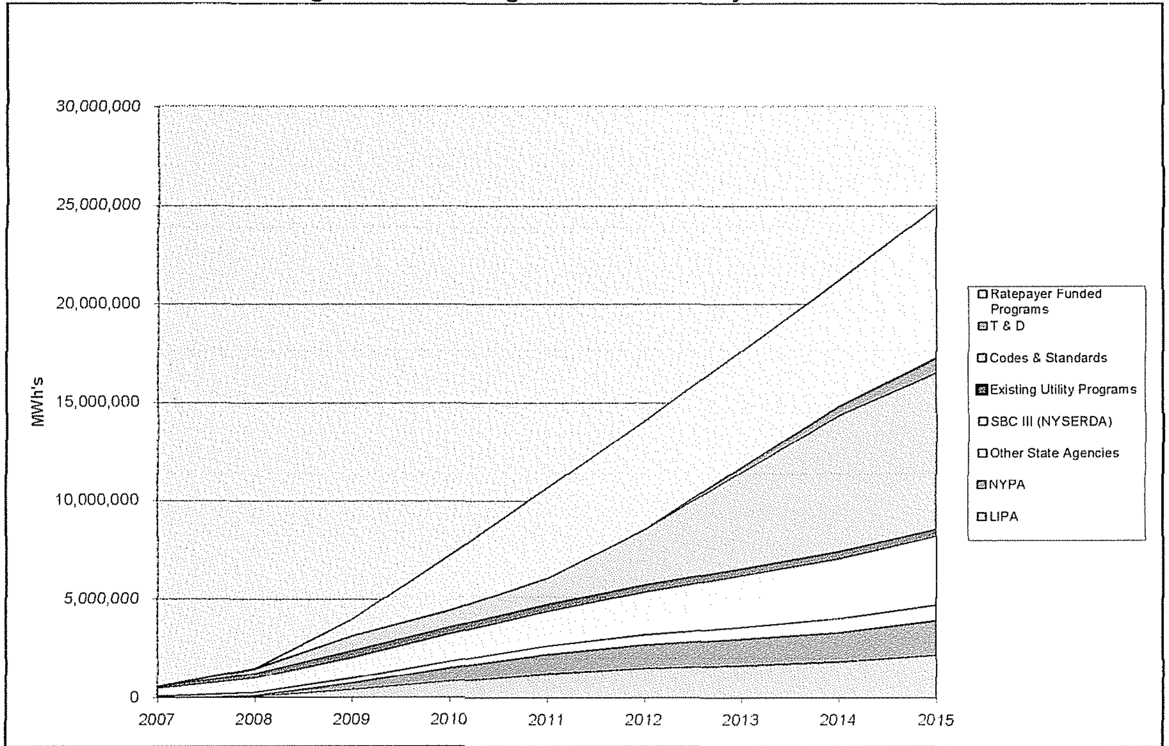
Electric EERS	15% Cumulative savings by 2015
Applicable Sector	Investor-owned utility, natural gas utilities with 14,000 or more customers
Natural Gas EERS	~14.7% by 2020
Authority 1 Date Enacted Date Effective	NY PSC Order, Case 07-M-0548 06/23/2008 06/23/2008
Authority 2 Date Enacted Date Effective	NY PSC Order, Case 07-M-0748 05/19/2009 05/19/2009

Legislative and Regulatory Background

On June 23, 2008, the New York Public Service Commission (NYPSC) issued a decision creating the New York Energy Efficiency Portfolio Standard (EEPS), which aimed to reduce electricity usage by 15% of forecast levels by 2015. NYPSC also approved natural gas efficiency targets in May 2009. The targets aim to save 4.34 Bcf annually through the end of 2011 and 3.45 Bcf annually beyond 2011. The downward revision of the target reflects a likely change in program balance following the exhaustion of federal stimulus funding. Combined with reductions from other sources, this target will result in a 14.7% reduction in estimated gas usage by 2020. New York's EEPS is delivered alongside a broad spectrum of research and development, business development, and market development programs.

New York has an array of program administrators that advance energy efficiency. The New York State Energy Research and Development Authority (NYSERDA) is the largest energy efficiency program administrator, followed by two additional major energy efficiency institutions: The New York Power Authority (NYPA), the largest state public power organization in the U.S., and the Long Island Power Authority (LIPA), which is structured as a non-profit municipal electricity provider and does not own any generation plants on Long Island. New York's investor-owned utilities also administer energy efficiency programs, the largest being Consolidated Edison in New York City and National Grid upstate, through its operating company, the Niagara Mohawk Power Corporation. All of these program administrators contribute to New York's 15x15 goal, as well as savings derived from other state agencies, codes and standards, and improvements to transmission and distribution. LIPA and NYPA, however, are not bound to the EEPS targets by regulation since they are not under the jurisdiction of the NYPSC. Thus while total electricity sales under the 15% by 2015 standard would require savings of roughly 29.4 million MWh annually in 2015, the NYPSC has approved program targets that leave roughly 7.7 million MWh to be achieved by programs outside its jurisdiction.

Figure 5: Achieving New York's "15 by 15" Goal



Source: New York State Energy Plan, Volume I. December 2009
http://www.nysenergyplan.com/final/New_York_State_Energy_Plan_VolumeI.pdf

As of December 31, 2010, the NYPSC approved 99 energy efficiency programs (48 electric and 51 gas). Energy savings targets are set annually for each program administrator based on its share of the 15x15 goal. The savings targets through December 31, 2010 amount to 1,846,025 Net MWh (about 1% annual savings) and 2,855,811 Dekatherms. NYSERDA is responsible for 62% of electricity savings and 56% of natural gas savings with IOUs responsible for the rest. The approved programs represent a total funding commitment of $1.1 billion, mostly through the end of 2011.

Energy Savings Achieved vs. Targeted

NYSERDA and the investor-owned utilities are performing below the near-term EEPS goals, but trends indicate the state is on track to meet its long-term targets. NYSERDA and the IOUs combined to meet 46.8% of their savings goal through 2010 but spent only 35.9% of what was budgeted for programs. Natural gas programs fared somewhat better, achieving 50.9% of the near-term energy savings goal and spending only 40.9% of the total budget through 2010

Table 23: Natural Gas and Electric Savings and Spending as Percent of Targets through 12/31/2010, by Program Administrator

Program Administrator	Percent of Net MWh Target Achieved	Percent of Budget Spent
Central Hudson	31.5%	37.2%
Con Edison	22.4%	24.6%
Niagara Mohawk	50.3%	72.2%
NYSEG	13.1%	20.0%
Orange and Rockland	23.9%	22.4%
Rochester Gas & Electric	27.9%	26.9%
NYSERDA	54.2%	29.9%
NEW YORK STATE	**46.8%**	**35.9%**

Program Administrator	Percent of Net Dekatherm Target Achieved	Percent of Budget Spent
Central Hudson	65.4%	74.2%
Con Edison	8.1%	17.4%
Corning	111.2%	106.7%
KED-LI	77.4%	71.1%
KED-NY	28.5%	30.9%
Niagara Mohawk	137.4%	95.0%
NYSEG	127.0%	126.1%
O&R	157.8%	118.0%
RG&E	166.8%	142.6%
St. Lawrence Gas	55.9%	49.8%
NYSERDA	28.0%	25.6%
NEW YORK STATE	**50.9%**	**40.9%**

Source: NYPSC EEEPS Program Implementation Status Through the 4th Quarter of 2010, March 2011

Factors Affecting Performance

Numerous barriers contributed to the slow start. The program approval period took longer than expected as Commission staff carefully examined the operating plans of the utilities, which had not been in the business of delivering efficiency programs for years. Once implemented, the recession negatively impacted program participation. Program administrators also identified market confusion as a concern. Since NYSERDA had been the sole supplier of energy efficiency for so long, customer awareness of the IOU programs is low. When they are aware, having two options makes their decisions more complicated. It is competitive, however, customers in general are not complaining because multiple financial incentive options allow them to choose those that best meet their needs.

New York has the funding, expertise and efficiency potential to meet their energy efficiency portfolio standard goals, and although there have been challenges since the adoption of the EEPS Order in 2008, there have been many initial successes. The programs in place are achieving higher levels of savings than expected, evidenced by the fact that savings levels are greater than spending levels in terms of percentage of expected values. Due to the scale and complexity of utility energy efficiency institutions and programs, one common element linking successful efforts to ramp-up savings is collaboration—especially collaboration across institutions that enables integration, coordination, and standardization. Stakeholders in New York recognize the need to build on these past successes.

Program Administrators state that the outlook for New York to achieve 15 by 2015 EEPS energy savings goals is good. The program plans submitted by electric program administrators supports this claim. Statewide, electric IOUs and NYSERDA forecast electric savings to meet 94% of the 2011 goal. Natural gas program administrators expect to achieve 75% of the statewide 2011 target.

Ohio

Summary

Electric EERS	22% by 2025 (0.3% annual savings in 2009, ramping up to 1% in 2014 and 2% in 2019)
Applicable Sector	Investor-owned utilities
Natural Gas EERS	None
Authority 1 Date Enacted	ORC 4928.66 et seq. 1/1/2009
Authority 2	S.B. 221

Legislative Background

Senate Bill 221, signed into law May 1, 2008, included both an Energy Efficiency Portfolio Standard (EEPS), and Alternative Energy Portfolio Standard (RPS), among other provisions. For efficiency, it requires a gradual ramp up to a cumulative 22 percent reduction in electricity use by 2025. Beginning in 2009, the Act requires electric distribution utilities to implement energy efficiency programs that achieve energy savings equal to at least three-tenths of one per cent of sales. The baseline for which energy savings is calculated against is the average number of total kilowatt hours sold by electric distribution utilities during the preceding three years. The standard ramps up as shown in the table below.

Table 24: Ohio's Energy Efficiency Portfolio Standard

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020-25
0.30%	0.50%	0.70%	0.80%	0.90%	1.00%	1.00%	1.00%	1.00%	1.00%	2.00%	2.00%

Failure to comply with energy efficiency savings requirements results in forfeiture on the utility. The amount is either that prescribed by the legislature or the existing market value of one renewable energy credit per MWh of undercompliance or noncompliance. Any revenue from forfeiture is credited to the Advanced Energy Fund. The commission may amend the benchmarks if, after application by the electric distribution utility, the commission determines that the utility cannot reasonably achieve the benchmarks due to regulatory, economic, or technological reasons beyond its reasonable control. Utilities must annually submit energy efficiency status reports and according to Ohio Administrative Code Section 4901:1-39-06(B), Commission Staff is required to review the reports and file its finding and recommendations regarding program implementation and compliance with applicable benchmarks.

The EEPS applies to Ohio's investor-owned utilities and retail suppliers. Ohio's largest electric utility is FirstEnergy, with 1.8 million customers in Ohio served by three operating companies: Ohio Edison, Toledo Edison, and the Cleveland Electric Illuminating Company. Second is American Electric Power of Ohio (AEP), with 1.5 million customers served by two operating companies: the Columbus Southern Power Company and the Ohio Power Company. Duke Energy Ohio and Dayton Power & Light Company (DP&L) both have over a half-million customers. These investor-owned utilities sell almost 90% of all retail electricity in the state.

Energy Savings Achieved vs. Targeted

According to self-reported data, AEP, Duke Energy, and DP&L exceeded their requirements in 2009 and 2010, while FirstEnergy fell far short in 2009 and will report on its 2010 savings in May 2011.[82] Program portfolios for AEP, DP&L, and Duke Energy as a whole were cost-effective in 2010 as determined by the Total Resource Cost test. These utilities' programs in 2009 and 2010 will save customers a net $351 million in utility costs over the program measures' lifetime.[83]

Unable to ramp up programs quickly, FirstEnergy received a waiver from the PUCO allowing it to meet the remainder of its 2009 requirements in future years.[84] Most recently, the PUCO waived annual requirements for FirstEnergy for 2009, 2010, 2011, and 2012. Instead, First Energy will be required to meet a cumulative benchmark by the end of 2012.[85] PUCO ruled that the Portfolio Plan, as filed by FirstEnergy, was not designed to meet the benchmarks in 2010, which PUCO addressed by allowing FirstEnergy to still comply by meeting a cumulative 2012 target (2.3%). FirstEnergy has applied for a rehearing regarding whether the plan was designed to achieve 2010 benchmarks, the results of which are pending at the Commission.

Table 25: Energy Efficiency Performance by Utility in 2009

Utility	2009 Requirement (MWh)	2009 Achieved (MWh)	Percent Attained	2010 Requirement (MWh)	2010 Achieved (MWh)	Percent Attained
American Electric Power[86]	136,944	**171,000**	125%	228,125	**306,000**	134%
Dayton Power & Light[87]	43,193	**40,442**	94%	71,781	**101,061**	141%
Duke Energy[88]	68,127	**86,402**	127%	109,420	**310,755**	284%
FirstEnergy[89]	166,310	**22,614**	14%	N/A	N/A	N/A
Total	**414,574**	**320,458**	**77%**	**409,326**	**717,816**	**175%**

Each utility has submitted plans to achieve their requirements through at least 2011, detailing program portfolios, budgets, and expected savings. Utilities also submit long-term plans forecasting their ability to meet targets in 2025. Except for Duke Energy, each utility projected savings levels in line with future requirements (Woodrum et al. 2010). In its long term forecast report, Duke Energy projected that it would not be able to cost-effectively achieve the long-term 22% requirement, forecasting that it could only meet 14 to 15 percent.[90] After a series of negotiations with stakeholders, however, Duke Energy agreed to a settlement agreement in which it agrees that "it is reasonable for Duke to assume that sufficient, cost-effective energy savings opportunities exist to allow the Company to meet the energy efficiency and demand reduction benchmarks stated in R.C. 4928.66 over the 10-year forecast period." It also states that CHP is a potentially cost-effective option for assisting Duke to meet its resource requirements.

Factors Affecting Performance

A number of factors drove the success of Ohio's other three utilities' meeting their goals in 2009 and 2010. Duke had programs approved prior to SB 221, allowing it to meet the requirements with programs already underway. AEP and DP&L began their energy efficiency efforts as a result of SB 221 and began with a portfolio of tried-and-true programs. Complementary policies allowing these

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[82] PUCO staff have yet to file their required report and findings on the energy efficiency status reports of any utilities, as required.
[83] Calculation by Dylan Sullivan, Natural Resources Defense Council. Based on utility presentations and evaluation reports.
[84] Order, January 7, 2010, Docket 09-1004-EL-EEC, et al.
[85] Order, March 23, 2011, Docket 09-1947-EL-POR, et al.
[86] Savings calculated on a pro-rated basis. 2009: Docket No. 10-0318-EL-EEC; 2010: 11-1299-EL-EEC
[87] Savings calculated on a pro-rated basis. Docket No. 10-0303-EL-POR; 2010: 11-1276-EL-POR
[88] Calculated as incremental savings. 2009: Docket No. 10-0317-EL-EEC (Appendix A); 2010: 11-1311-EL-EEC
[89] Requirements for 2009 through 2012 waived. 2009 savings achieved filed in Docket No. 10-0277-EL-EEC
[90] Duke Long Term Forecast Repot 2010

three utilities to recover program costs and in AEP and Duke's case, earn performance incentives on well-performing programs have also helped drive energy savings.

Funding Levels

In order to achieve sustained levels of savings required in Ohio's EEPS, utilities are ramping up budgets to develop the necessary program delivery infrastructure. Ohio's electric utilities increased their collective budgets for energy efficiency programs from approximately $20 million per year between 2006 and 2008 to $152.8 million in 2010, according to the Consortium for Energy Efficiency.

Meeting Future Goals

Utilities are now initiating the three year efficiency portfolio and program planning cycle for 2012-14. As utilities in Ohio shape plans to meet Ohio's aggressive requirements, they may look to a report by ACEEE, together with Summit Blue Consulting, "Shaping Ohio's Energy Future: Energy Efficiency Works," which recommends five innovative programs to complement other proven utility programs: advanced residential and commercial buildings initiatives; manufacturing and rural and agriculture initiatives; and combined heat and power programs. Together, the innovative initiatives recommended would achieve about half of the 22% savings required under the EEPS by 2025.

According to AEP, most of the programs they put into place over the next three year cycle will be similar to current programs. In the longer term beyond the next 3 to 5 years, they will assess industrial long-range planning, continuous improvement, and integrating energy efficiency with industrial process improvement to achieve deeper levels of energy savings. For Duke Energy Ohio, much of their efficiency program outlook depends on changes to codes and standards, and how utilities may or may not get credit for part of the savings due to them. The utility claims that this issue heavily influences the types of programs they offer, especially when planning 7 or 8 years into the future. Ohio utilities are informally discussing how to design a building codes enhancement and compliance support program. The next phase of portfolio plans will likely include a building codes enhancement program.[91]

EERS under Fire

On March 23, 2011, First Energy and DP&L both submitted testimony to the State Senate Energy and Public Utilities Committee requesting the legislature to revisit Ohio's EERS. The utilities expressed frustration with the lack of clarity of whether savings should be calculated as annualized or pro-rated, and recommended the targets be halved. Although the original S.B. 221 was unclear on the proper savings methodology, the Commission rejected the use of annualized savings on multiple occasions.[92]

Pennsylvania[93]

Summary

Electric EERS	3% cumulative savings by 2013
Applicable Sector	Investor-owned electric distribution companies
Natural Gas EERS	None
Authority 1 Date Enacted Date Effective	66 Pa C.S. § 2806.1 10/15/2008 11/14/2008
Authority 2 Date Enacted	PUC Order Docket No. M-2008-2069887 1/15/2009

[91] Personal conversation, Daniel Sawmiller, Ohio Consumers Counsel. May 5, 2011.
[92] 08-888-EL-ORD, Entry on Rehearing (June 17, 2009) at 9.
[93] While PA PUC has reviewed this document, it does not endorse its findings

Legislative and Regulatory Background

In October 2008 Pennsylvania adopted Act 129, establishing an energy efficiency resource standard in Pennsylvania. Each electric distribution company (EDC) with at least 100,000 customers[94] must reduce energy consumption by a minimum 1% by May 31, 2011, increasing to 3% by May 31, 2013, measured against projected electricity consumption for the period from June 2009 to May 2010. Peak demand must be reduced by 4.5% by May 31, 2013. Ten percent of both consumption and peak demand reductions are to come from federal, state, and local government, including municipalities, school districts, institutions of higher education and nonprofit entities. Another ten percent must come from the low-income sector. The Pennsylvania Public Utility Commission (PUC) approved Energy Efficiency and Conservation (EE&C) plans for each EDC, which detailed program portfolios and savings targets tailored to each EDC. The PUC may also set targets for the period beyond 2013. Failure to achieve the reductions required (load and/or peak demand) subjects EDCs to a civil penalty of not less than $1M and not to exceed $20M.

Under the new legislation, the EDCs' EE&C plans propose a cost-recovery tariff mechanism to fund the EE&C measures and to ensure recovery of reasonable costs. The EDCs can also recover the costs through a reconcilable adjustment mechanism. The total cost associated with an EDC's energy efficiency and peak demand reduction plan may not exceed 2% of the EDC's total annual revenue as of December 31, 2006.

Energy Savings Achieved vs. Targeted

Pennsylvania EDCs officially began implementing programs counting towards their EERS on June 1, 2009. The 2nd quarter report of Program Year (PY) 2 indicates all of Pennsylvania's utilities are achieving significant savings levels.[95] Through November 2010, utilities had achieved approximately 58% of the 2011 goal, roughly on track to meet the 1% savings goal by June 2011.[96] Results for Program Year 2 have been promising given that in Program Year 1 utilities only achieved ~20% of the goal. In the cases of Allegheny, Met-Ed, and Penelec, savings in the 1st quarter of Program Year 2 exceeded all of those of PY 1. Twenty-seven programs began in the 1st quarter of PY 2, compared to 38 initiated in all of PY 1. The presence of a Statewide Evaluator (SWE) has been an extremely positive development for the state's utilities. The SWE provides timely reports that allow utilities to gauge performance and verify savings.

Table 26: Pennsylvania EERS Targets vs. Achieved

Program Administrator	Percent of 2011 Target Achieved end of PY 1	Percent of 2011 Target Achieved end of 2nd Quarter, PY 2	Percent of 2013 Target Achieved to date
Allegheny	1.4%	1.4%	0.5%
Duquesne	19.0%	22.4%	7.5%
Met-Ed	8.2%	37.1%	12.4%
Penelec	8.9%	45.4%	15.1%
Penn Power	11.7%	46.0%	15.3%
PECO	40.0%	113.0%	38.0%
PPL	22.0%	62.0%	21.0%
STATEWIDE*	**19%**	**58%**	**19.3%**

Source: Act 129 Statewide Evaluator Quarterly Report, Program Year One and Second Quarter, Program Year Two
*ACEEE Estimate, not endorsed by PA PUC

[94] Standards apply to the following utilities: PECO Energy, PPL Electric Utilities, West Penn Power (Allegheny), Pennsylvania Power Company (PennPower) Pennsylvania Electric (Penelec), Metropolitan Edison (Met-Ed), and Duquesne Light.
[95] Pennsylvania has a Statewide Evaluator, which reports on implementation status quarterly. As of the drafting of this report, the latest confirmed savings data comes from Program Year 2 (2010-2011) 2nd Quarter Report.
[96] Through six of the eight quarters given for utilities to meet the 1% goal in 2011, the theoretical "on-track" savings figure would be 75%.

Iowa

Summary

Energy Efficiency EERS	Varies by utility from 1-1.5% annually by 2013
Applicable Sector	Investor-owned utilities, Municipal utilities, Co-operatives
Natural Gas EERS	Annual goals by 2013 vary by utility: 0.74% (Muni's), 0.85% (MidAmerican); 0.94% (Black Hills) 1.2% (IPL)
Authority 1	Iowa Code § 476
Authority 2 Date Enacted Date Effective	Senate Bill 2386 5/06/2008 5/06/2008

Legislative and Regulatory Background

Iowa's utilities administer energy efficiency programs under a regulated structure with oversight by the Iowa Utilities Board (IUB) and significant input from the Office of Consumer Advocate and other energy efficiency stakeholders. Iowa Code 476.6.16 mandates that investor-owned utilities offer energy efficiency programs through cost-effective energy efficiency plans. The utilities recover program costs of the plans approved by the IUB through adding tariff riders to customer bills. Most publicly owned utilities in Iowa (municipal utilities), as well as rural electric cooperatives, provide energy efficiency programs, ensuring nearly statewide coverage. Iowa's utilities have long records of funding and providing comprehensive portfolios of energy efficiency programs to all major customer categories — residential, commercial, industrial and agricultural. Aside from a decrease in funding in the late 1990s as the state considered restructuring proposals, Iowa has long been a nationwide leader delivering utility energy efficiency programs.

Senate Bill 2386 amended Iowa Code 476.6, among other provisions, requires the IUB to develop energy savings performance standards for each utility. Each utility must file plans to meet specific energy efficiency goals. In compliance with this bill, the Iowa Utilities Board (IUB) issued an order asking investor-owned utilities (IOUs) to submit plans including a scenario to achieve a 1.5% annual electricity and natural gas savings goal.[97] Iowa's two investor-owned electric utilities, Interstate Power and Light Company (IPL) and MidAmerican Energy Company, complied with this request by filing Energy Efficiency Plans for 2009-2013 that outline how the utilities could meet the 1.5% electric target.[98] Both utilities determined the 1.5% natural gas target would be unattainable. While MidAmerican plans to meet the 1.5% electric goal, the IUB declined to approve a slightly lower electric goal for IPL due to potential rate impacts on IPL customers. Both IPL and MidAmerican's goals represent levels of electric savings around twice the levels achieved in 2008. Municipal and cooperative utilities also are required to implement energy efficiency programs, set energy savings goals, create plans to achieve those goals, and report to the IUB on progress.[99] Municipal and co-operative utilities filed goals on December 31, 2009.

Iowa's natural gas utilities also set annual energy efficiency savings targets for the period between 2009 and 2013. Annual goals vary—municipal utilities plan to save 0.74% by 2013; MidAmerican 0.85%; Black Hills Energy 0.94%; and IPL 1.2%.

Energy Savings Achieved vs. Targeted

As noted in the table below, both of Iowa's electric IOUs exceeded 2009 savings targets cost-effectively. Both MidAmerican and IPL reached customers in all sectors, using both traditional and innovative program designs to advance energy efficiency. IPL, in particular, received numerous accolades recognizing its excellence in marketing and education.

[97] Docket No. 199 IAC 35.4 (EEP-02-38; EEP-03-1; EEP 03-4), January 14, 2008.
[98] MidAmerican Energy Company: Docket No. Docket No. EEP-08-2. Interstate Power and Light Company: Docket No. EEP-08-1.

Table 27: Iowa Utility Savings Targets as % of Sales

Utility	2009 Goal	2009 Achieved	2010 Goal	2011 Goal	2012 Goal	2013 Goal
MidAmerican	1.09%	**1.2%**	1.50%	1.54%	1.51%	1.50%
Interstate Power and Light	0.9%	**1.3%**	0.9%	1.0%	1.2%	1.3%
Municipal Utilities*	NA	NA	0.71%	NA	1.09%	NA
Electric Cooperatives**	NA	NA	1.1%	NA	1.2%	NA

*Average Goals of Iowa Association of Municipal Utilities
**Average Goals of Iowa Association of Electric Cooperatives
Sources: IOUs: 2011 Operating Plans and Annual Reports for Program Year 2009. Muni's and Co-ops: "Evaluation of Energy Efficiency Goals and Programs Filed with the Iowa Utilities Board by the Iowa Association of Municipal Utilities" and "Evaluation of Energy Efficiency Goals and Programs Filed with the Iowa Utilities Board by the Iowa Association of Electric Cooperatives."

Factors Affecting Performance

Uncertainty looms in the years ahead, however, as a result of the recession. MidAmerican noted in its Annual Report for Program Year 2009 that the weakened economy dampened demand for some programs, especially residential and low-income, while the promise of reduced costs drove demand for other programs or parts of programs. Because of the unknown impact of the economy on energy efficiency, MidAmerican will place emphasis in the near future on low cost efficiency and efficiency that can be achieved through behavior change.

Funding Levels

In order to achieve levels of savings unattained in previous years, Iowa's utilities are increasing cost-effective spending on electric energy efficiency programs to meet their goals. IPL and MidAmerican plan to increase direct spending on programs from 2009 to 2013 by 30% ($60 to $78 million for IPL) and 37.5% ($40 to $55 million for MidAmerican), respectively. Municipal utilities will increase spending by 32 percent from 2010 to 2012 and electric cooperatives will increase spending by 12 percent from 2010 to 2014.

Collaboration among Stakeholders

As they ramp up savings, Iowa recognizes the importance of coordination among the numerous utilities in the state. To achieve this objective, the state's IOUs, municipal, and co-operative utilities participate in the Statewide Energy Efficiency Collaborative, sponsored by the OCA. The Collaborative helps utilities identify and advance, where appropriate, areas of coordinated energy efficiency processes. The Collaborative also includes other energy efficiency stakeholders to share best practices and investigate opportunities for deeper savings and new programs.

Massachusetts

Summary

Electric EERS	State law requires the electric distribution utilities to procure all cost-effective efficiency resources through a 3-year Efficiency Procurement Plan and requires full funding of the Plan. After the required review and input by a key stakeholder efficiency council (which included a unanimous 11-0 vote), the Commission approved and fully funded the 2010-2012 Efficiency Procurement Plan in January of 2010 which includes electric utility savings targets of 1.4% in 2010, 2.0% in 2011; 2.4% in 2012

Applicable Sector	Utility, Investor-owned utilities, Cape Light Compact
Natural Gas EERS	State law requires the natural gas distribution utilities to procure all cost-effective efficiency resources through a 3-year Efficiency Procurement Plan and requires full funding of the Plan. After the required review and input by a key stakeholder efficiency council (which included a unanimous 11-0 vote), the Commission approved and fully funded the 2010-2012 Efficiency Procurement Plan in January of 2010 which includes natural gas utility savings targets of 0.63% in 2010, 0.83% in 2011, 1.15% in 2012
Authority 1	D.P.U. Order on Electric Three-Year Energy Efficiency Plans, 2010-2012 (D.P.U. 09-116 through D.P.U 09-120)
Statutory Authority	Mass. Gen. Laws c. 25 § 21.

Legislative and Regulatory Background

Massachusetts is a leading state for utility energy efficiency programs with a successful implementation record spanning over 30 years and across all customer sectors. The Green Communities Act of 2008 ushered in a new era for greatly expanded efficiency programs by establishing an "efficiency procurement" approach to EERS policies. That is, the Green Communities Act requires electric and natural gas distribution utilities to invest in all cost-effective energy efficiency that is cheaper than supply resources. Starting in the fall of 2009, and triennially thereafter, the distribution utilities are now required to propose a joint, comprehensive, fully funded state-wide 3-year efficiency plan (for 2010-2012) to satisfy the all cost-effective efficiency procurement requirement for input and review by a new diverse stakeholder efficiency council. This new Massachusetts Energy Efficiency Advisory Council (EEAC) plays a central role in planning and overseeing the utilities' program administration. The EEAC is an 11 member stakeholder body, representing commercial, industrial, residential, low income, labor, and environmental interests, chaired by Massachusetts Department of Energy Resources (DOER), which works collaboratively with the utilities to develop state-wide coordinated energy efficiency plans. After EEAC review and approval, plans are submitted to the Department of Public Utilities (DPU) for analysis and cost-effectiveness testing. The EEAC and DOER help to keep programs on track to meet their energy savings goals. Plans are updated annually and may be modified mid-term. There are five electric energy efficiency program administrators and seven gas program administrators, whose work is overseen by the EEAC and approved by the DPU.

The Green Communities Act requires that electric and gas utilities procure all cost-effective energy efficiency before more expense supply resources, requiring a three year planning cycle. On January 28th, 2010 the DPU approved the first 3-year (2010-2012) electric and gas energy efficiency plans under the Green Communities Act, paving the way for the realization of the goals and efficiency procurement requirement established in the Act. The electric efficiency procurement plan is fully funded and ramps up savings each year, from a starting point of 1.0% in 2009, to 1.4% in 2010, 2.0% in 2011, and then to 2.4% of retail electricity sales in 2012. 2.4% is equivalent to a first year savings of 1,103 GWh in 2012. The energy efficiency investments in 2010-2102 will save 2,625 gigawatt-hours (GWh) of electricity in 2012 (the cumulative annual impact in 2012). The statewide totals are comprised entirely of the individual program administrator savings.[100]

Massachusetts's efficiency procurement approach to their EERS has resulted in one of the most, if not the most ambitious fully funded savings targets of any state. With annual electricity savings of 2.4 percent per year going forward from 2012, the Massachusetts programs would achieve cumulative annual energy savings equivalent to 30 percent of retail electricity sales in 2020. Customers will use 23.4% less electricity in 2020 than they were forecasted to use (based on the April 2009 revised ISO-NE CELT forecast). Retail energy use in 2020 will be 12.5% less than what customers used in 2009,

[100] D.P.U. Order on Electric Three-Year Energy Efficiency Plans, 2010-2012 (D.P.U. 09-116 through D.P.U 09-120)

thereby reducing customer energy use over the next 11 years. (In visual terms, this will bend the curve of projected demand down.)

The natural gas plan will save 24.7 million therms in 2012, equivalent to 1.15 percent of retail natural gas sales in 2012. The fully funded energy efficiency investments in 2010-2102 will save over 57.3 million therms of natural gas in 2012 (the cumulative annual impact in 2012). The lifetime energy savings for the gas three-year plan will be almost 897 million therms.[101] Overall, the fully funded 2010-2012 electric and natural gas efficiency procurement plans will yield net consumer savings of more than $3.9 billion, reduce statewide carbon dioxide emissions by nearly 15 million short tons, and create more than 3,800 local jobs (ENE 2010).[102]

Energy Savings Achieved vs. Targeted

According to the fourth quarter report from the Massachusetts Program Administrators in 2010, the state is on track to meet its 2010 electric and natural gas requirements. The preliminary data shows PA's meeting 98% of their MWh goals, 103% of their Therms goals, and spending less than the allotted budget on electric and natural gas programs.[103]

Table 28 : Massachusetts Electric Savings Targets and Savings Achieved, 2010-2012

Year	Savings Target as Percent of Sales	Savings Goal (MWh)	Electric Savings Achieved (MWh)	Percent of Target Achieved
2010	1.4%	625,004	609,788	98%
2011	2.0%	897,232		
2012	2.4%	1,103,423		
2010-2012	**5.8%**	**2,625,083**		

Note: Data is preliminary and subject to revision and check.
Source: Quarterly Report of the Program Administrators, Fourth Quarter, 2010. February 3, 2011

Table 29: Massachusetts Natural Gas Savings Targets and Savings Achieved, 2010-2012

Year	Savings Target as Percent of Sales	Savings Goal (Therms)	Natural Gas Savings Achieved (Therms)	Percent of Target Achieved
2010	0.63%	13,586,666	13,926,865	103%
2011	0.89%	19,087,301		
2012	1.15%	24,687,219		
2010-2012	**2.67%**	**56,368,432**		

Note: Data is preliminary and subject to revision and check.
Source: Quarterly Report of the Program Administrators, Fourth Quarter, 2010. February 3, 2011

Factors Affecting Performance

Funding Levels

A major input required to make steep increases in energy savings attainable and sustainable will be unprecedented funding increases. According to the State of Massachusetts Department of Energy Resources (DOER), electric utilities budgeted $183.8 million for 2009 electric energy efficiency programs from ratepayer-funded sources, a 46 percent increase over 2008 spending. Required by the Green Communities Act, full funding for the procurement all cost-effective efficiency resources was proposed as part of the utilities' 3-year plans, reviewed and endorsed by the EEAC, and then

[101] D.P.U. Order on Gas Three-Year Energy Efficiency Plans, 2010-2012 (D.P.U. 09-121 through D.P.U. 09-128
[102] ENE (Environment Northeast) Spring 2010. *Efficiency Ramps up in Massachusetts*. Boston: ENE (Environment Northeast)
[103] A report with verified savings will be issued in mid- to late-2011.

approved by the DPU. Sources of funding include the System Benefits Charge on customer bills, an adjusting charge approved by DPU, revenues from the ISO New England (ISONE) Forward Capacity Market, and proceeds from the Regional Greenhouse Gas Initiate (RGGI). The Green Communities Act dedicates 80% of RGGI funds to energy efficiency.

Decoupling and Performance Incentives

Massachusetts is currently implementing decoupling for all of its gas and electric utilities: each utility must now include a decoupling proposal as a component of its next rate case to fully remove the disincentive to larger consumer efficiency programs.[104] To date, the state has five fully decoupled local distribution companies—National Grid Electric, Western Massachusetts Electric Company, Bay State Gas, National Grid Gas, and New England Gas. A shareholder incentive currently provides an opportunity for companies to earn about 5% of program costs as an incentive for meeting program goals. The incentive is based on a combination of elements including energy savings, net benefits to customers, and market transformation results.

Meeting Future Goals

The utility program administrators are implementing the strategic principle of accessing deeper savings first with statewide coordination and the active involvement of the EEAC. Deeper savings begin with planning for increased budgets for rebates and other financial incentives combined with increased one-on-one customer contact. Key to ongoing success in Massachusetts will be the continued leadership and long-term perspective from PAs, the EEAC and the state regulators, transparency and stakeholder participation, and continuous improvement and innovation in program offerings to improve the customer experience. A full discussion of Massachusetts's experience and programmatic successes can be found in Nowak et al. (2011).

[104] DPU Docket 07-50-A (July 2008)

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STATE OF SOUTH CAROLINA	BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA
(Caption of Case) IN RE: Duke Energy Carolinas, LLC's 2011 Integrated Resource Plan (IRP)	COVER SHEET
	DOCKET NUMBER: 2011 - 10 - E

(Please type or print)

Submitted by:	Charles A. Castle	SC Bar Number:	79895
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NOTE: The cover sheet and information contained herein neither replaces nor supplements the filing and service of pleadings or other papers as required by law. This form is required for use by the Public Service Commission of South Carolina for the purpose of docketing and must be filled out completely.

DOCKETING INFORMATION (Check all that apply)

☐ Emergency Relief demanded in petition ☐ Request for item to be placed on Commission's Agenda expeditiously

☒ Other: Duke Energy Carolinas' 2011 Integrated Resource Plan and Motion for Confidential Treatment

INDUSTRY (Check one)	NATURE OF ACTION (Check all that apply)		
☒ Electric	☐ Affidavit	☐ Letter	☐ Request
☐ Electric/Gas	☐ Agreement	☐ Memorandum	☐ Request for Certification
☐ Electric/Telecommunications	☐ Answer	☒ Motion	☐ Request for Investigation
☐ Electric/Water	☐ Appellate Review	☐ Objection	☐ Resale Agreement
☐ Electric/Water/Telecom.	☐ Application	☐ Petition	☐ Resale Amendment
☐ Electric/Water/Sewer	☐ Brief	☐ Petition for Reconsideration	☐ Reservation Letter
☐ Gas	☐ Certificate	☐ Petition for Rulemaking	☐ Response
☐ Railroad	☐ Comments	☐ Petition for Rule to Show Cause	☐ Response to Discovery
☐ Sewer	☐ Complaint	☐ Petition to Intervene	☐ Return to Petition
☐ Telecommunications	☐ Consent Order	☐ Petition to Intervene Out of Time	☐ Stipulation
☐ Transportation	☐ Discovery	☐ Prefiled Testimony	☐ Subpoena
☐ Water	☐ Exhibit	☐ Promotion	☐ Tariff
☐ Water/Sewer	☐ Expedited Consideration	☐ Proposed Order	☒ Other: 2011 Integrated Resource Plan
☐ Administrative Matter	☐ Interconnection Agreement	☐ Protest	
☐ Other:	☐ Interconnection Amendment	☐ Publisher's Affidavit	
	☐ Late-Filed Exhibit	☐ Report	

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September 1, 2011

VIA L C N C L NG AND
H. N E E C F DENTIAL VERSION

Ms. Jocelyn Boyd
hief Clerk e ssion
Public Servi C n of South Carolina
Synergy Bu s , aluda Building
101 Executi C r D ve
olumbia, SC

Re: Duke Ene C 11 Integrat d Resource Plan
Motion fo n
Docket N

Dear Ms.

Enclosed for filing please find C F DENTIA ERSION of Duke Energy Carolinas, LLC's ("Duke Energy Carolinas" or "the Com " I Integra source Plan ("2011 IRP"). Th C respectfully requests that it be permitted C NFIDE T L VERSION under seal and m confidential pursuant to Order No. 2005-2 , ' R RE U NG D SIGNATION O CONFI E TI L MATERIALS.'

The 2010 IRP contains certain confid ntial information (portions of the tables in Appendix (pages 139-141) and the tables in Appendix I (page 165)). The information contained therein is proprietary and commercially sensitive, and, if disclosed, could adversely affect the Company's ability to provide least cost resources for it ers. In addition, Appendix F of the 20 1 IRP contains Duke E ergy arolinas' most recently-filed FE C F rm 715. As FERC Form 715 contains critical energy infrast cture information that should be kept confidential and non-public, Duke Energy Caroli as is also filing it under seal and requests that the Commission treat this information as confidential and protect t from public disclosure

Thus, Duke E ergy Carolinas respectfully requests hat the Comm it e est for confidential treatment suant to 26 S.C. Code Ann. Regs. 103 804(S)(2)(Supp. y f Public version of the 2011 IRP is being filed electronically and a copy o the CONFIDE T L E S ON he 2011 IRP is being hand delivered to the Commission and the Office of Regulatory Staff ea

Please consider this correspondence as Duke Energy Carolinas Motion f C l tment of the above referen ed information in Appendices C, F and I of the 2011 IRP

hank you for your consideration of this matter and pleas contact me with any questions

Very trul yours

Charles A. Castle

Enclosures
cc: Shannon Bowyer Hudson, Esq.

The Duke Energy Carolinas Integrated Resource Plan (Annual Report)

September 1, 2011

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Although the supply-side screening curves showed that some of these resources would be screened out, they were included in the next step of the quantitative analysis for completeness.

Energy Efficiency and Demand-Side Management

EE and DSM programs continue to be an important part of Duke Energy Carolinas' system mix. The Company considered both demand response and conservation programs in the analysis.

The Company modeled the costs and impacts from EE and DSM programs based on the data included in Duke Energy Carolinas' approved Energy Efficiency Plan settlement in NCUC Docket No. E-7, Sub 831. For the analysis, Duke Energy Carolinas assumed these costs and impacts would continue through the duration of the planning period.

The forecasted energy efficiency savings through 2012 are consistent with Duke Energy Carolinas' North Carolina Energy Efficiency Plan for 2009 through 2012. The Company assumes for purposes of the IRP that total efficiency savings will continue to grow on an annual basis through 2031, however the components of future programs are uncertain at this time and will be informed by the experience gained under the current plan.

Develop Theoretical Portfolio Configurations

The Company conducted a screening analysis using a simulation model to identify the most attractive capacity options under the expected load profile as well as under a range of risk cases. This analysis began with a set of basic inputs which were varied to test the system under different future conditions, such as changes in fuel prices, load levels, and construction costs. These analyses yielded many different theoretical configurations of resources required to meet an annual 17 percent target planning reserve margin while minimizing the long-run revenue requirements to customers, with differing operating (production) and capital costs.

The set of basic inputs included:

- Fuel costs and availability for coal, gas, and nuclear generation;
- Development, operation, and maintenance costs of both new and existing generation;
- Compliance with current and potential environmental regulations;
- Cost of capital;
- System operational needs for load ramping, spinning reserve (10 to 15-minute start-up)

- The projected load and generation resource need; and
- A menu of new resource options with corresponding costs and timing parameters.

Duke Energy Carolinas reviewed a number of variations to the theoretical portfolios to aid in the development of the portfolio options discussed in the following section.

Develop Various Portfolio Options

Using the insights gleaned from developing theoretical portfolios, Duke Energy Carolinas created a representative range of generation plans reflecting plant designs, lead times and environmental emissions limits. Recognizing that different generation plans expose customers to different sources and levels of risk, the Company developed a variety of portfolios to assess the impact of various risk factors on the costs to serve customers. The portfolios analyzed for the development of this IRP were chosen in order to focus on the optimal timing of CT, CC, and nuclear additions in the 2016 – 2031 timeframe.

The information as shown on the following pages outlines the planning options that the Company considered in the portfolio analysis phase. Each portfolio contains demand response and conservation identified in the base EE and DSM case and renewable portfolio standard requirements modeled after the NC REPS in NC and applied to SC. In addition, each portfolio contains the addition of Cliffside Unit 6 in 2012, Buck CC in 2012 and Dan River CC in 2013 and the unit retirements shown in Table 5 D.

The RPS assumptions are based on NC REPS in North Carolina. The assumptions for planning purposes are as follows:

Overall Requirements/Timing
- 3% of 2011 load by 2012
- 6% of 2014 load by 2015
- 10% of 2017 load by 2018
- 12.5% of 2020 load by 2021

Additional Requirements
- Up to 25% from EE through 2020
- Up to 40% from EE starting in 2021
- Up to 25% of the requirements can be met with out-of-state, unbundled RECs
- Solar requirement
  - 0.02% by 2010
  - 0.07% by 2012

    - 0.14% by 2015
    - 0.20% by 2018
- Hog waste requirement (NC only – using Duke Energy Carolinas' share of total North Carolina load which is approximately 42%)
    - 0.07% by 2012
    - 0.14% by 2015
    - 0.20% by 2018
- Poultry waste requirement (NC only - using Duke Energy Carolinas' share of total North Carolina load which is approximately 42%)
    - 71,400 MWh by 2012
    - 294,000 MWh by 2013
    - 378,000 MWh by 2014

The overall requirements were applied to all retail load and to wholesale customers who have contracted with Duke Energy Carolinas to meet their REPS requirement. The requirement that a certain percentage must come from Hog and Poultry waste was not applied to the South Carolina portion.

Conduct Portfolio Analysis

Duke Energy Carolinas tested the portfolio options under the nominal set of inputs, as well as a variety of risk sensitivities and scenarios, in order to understand the strengths and weaknesses of various resource configurations and evaluate the long-term costs to customers under various potential outcomes.

For this IRP analysis, the Company selected six main scenarios to illustrate the impacts of key risks and decisions. Three of these scenarios fall into the Reference CO_2 Case and three fall into the Clean Energy Legislation Case.

- Reference Case: Cap and trade program with CO_2 prices based on Duke Energy's 2011 fundamental prices.
- Clean Energy Legislation: In addition to evaluating potential CO_2 cap and trade options, the impact of proposed Clean Energy legislation without a price on CO_2 emissions was also evaluated. Assumptions used in this analysis include:
    - 10% of retail sales by 2015 must be clean energy, increasing to 30% by 2030.
    - Alternative Compliance Payment (ACP) of 50$/MWhr.
    - "Clean Energy" includes renewable resources, EE, nuclear, natural gas CC, or alternative compliance payment.
    - Portfolios based on this legislation include the increased EE to meet 25

percent of the total clean energy target.

The six analyzed portfolios are shown below:

Reference CO_2 Case Scenarios:

1. Natural Gas – Combustion turbine/combined cycle portfolio (CT/CC)
2. Lee Nuclear – Two Lee Nuclear unit portfolio with units on-line in 2021 and 2023 (2N 2021-2023)
3. Regional Nuclear – Co-ownership of nuclear units in the region. The portfolio consists of 215 MW of nuclear in 2018, 730 MW in 2021 and 2023, and 559 MW in 2028 (Reg Nuclear)

Clean Energy Legislation Scenarios:

4. Clean Energy CC – CC portfolio with the Clean Energy Legislation assumptions
5. Clean Energy 2N – Two Lee Nuclear unit portfolio with the Clean Energy Legislation assumptions
6. Clean Energy Regional Nuclear – Regional co-ownership of nuclear with the Clean Energy Legislation assumptions

An overview of the specifics of each portfolio is shown in Table A.1 below.

The sensitivities chosen to be performed for these scenarios were those representing the highest risks going forward.

The Company evaluated the following sensitivities in the Reference CO_2 Case scenarios:

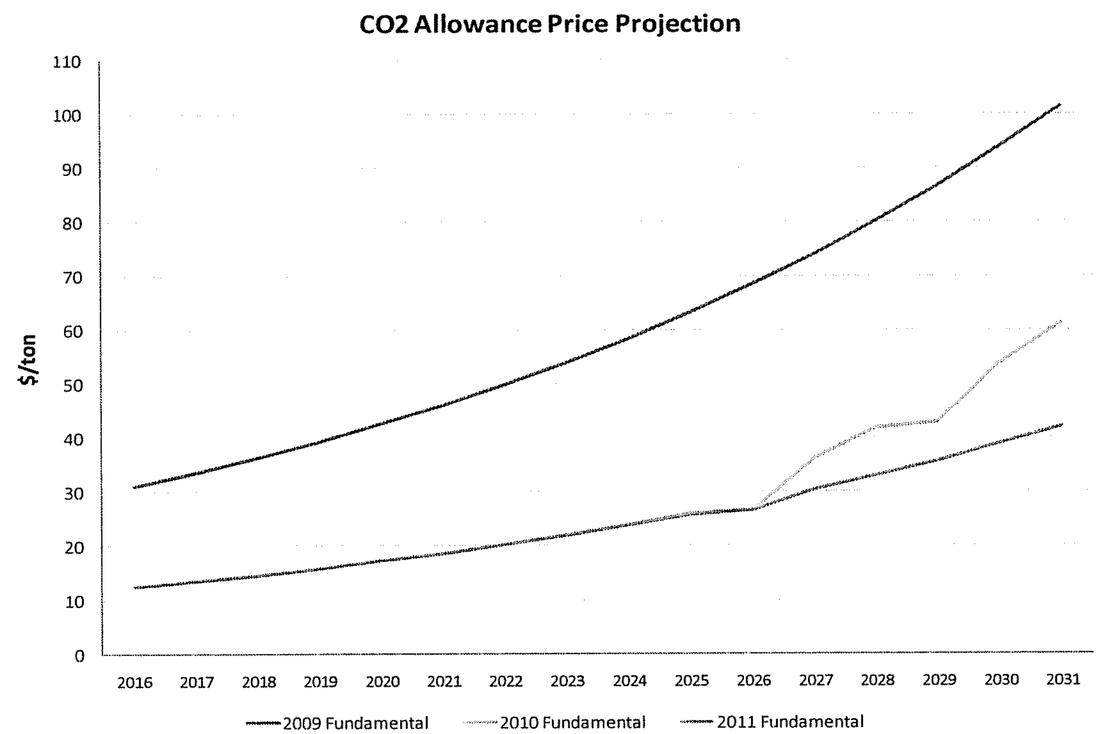
- Load forecast variations
  - Increase relative to base forecast (+15% for peak demand and +16% for energy by 2031)
  - Decrease relative to base forecast (-8% for peak demand and energy by 2031)
- Construction cost sensitivity[5]
  - Costs to construct a new nuclear plant (+20/- 10% higher than base case)
- Fuel price variability
  - Higher Fuel Prices (coal prices 25% higher, natural gas prices 25% higher)
  - Lower Fuel Prices (coal prices 40% lower, natural gas prices 40% lower)

[5] These sensitivities test the risks from increases in construction costs of one type of supply-side resource at a time. In reality, cost increases of many construction component inputs such as labor, concrete and steel would affect all supply-side resources to varying degrees rather than affecting one technology in isolation.

- Nuclear Financing
    - Federal loan guarantees for the Lee nuclear station
- The Carbon reference case had CO_2 emission prices ranging from $12/ton starting in 2016 to $42/ton in 2031. The Company performed sensitivities based on the 2009 and 2010 fundamental CO_2 prices.
- High Energy Efficiency – This sensitivity includes the full target impacts of the Company's save-a-watt bundle of programs for the first five years and then increases the load impacts at 1% of retail sales every year after that until the load impacts reach the economic potential identified by the 2007 market potential study. When fully implemented, this increased EE impacts resulted in approximately a 13% decrease in retail sales over the planning period.

Chart A.1 shows the CO_2 prices utilized in the analysis.

Chart A.1



For the Clean Energy Legislation, the Company also performed a sensitivity by lowering the ACP to $30/MWhr and increasing the renewable energy assumptions to lower the Company's need to purchase ACPs.

Georgia Power Company's Application for Decertification of Plant Branch Units 1 & 2 and Plant Mitchell Unit 4C, Application for Certification of the Power Purchase Agreements with BE Alabama LLC from the Tenaska Lindsay Hill Generating Station and with Southern Power Company from the Harris, West Georgia and Dahlberg Electric Generating Plants, and Updated Integrated Resource Plan

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Docket No. 34218

August 4, 2011

5. 2011 Unit Retirement Study

5.1 Introduction

Unit Retirement Study evaluations were performed for each Georgia Power coal unit that has not already incurred significant expenditures for environmental controls. For each of the analyses below (Sections 5.5.1-5.5.10), the Unit Retirement Study evaluated controlling or replacing the units in 2015 based on current expected compliance requirements and such analysis was used in the Company's decision to control, fuel switch, retire, or defer. For some of the units recommended for deferral that would not be able to be controlled in time for a 2015 Utility MACT compliance date, an additional analysis was conducted to determine the potential impacts of adding controls equipment at a later date. This additional analysis assumed that such units would be unavailable from 2015 until the projected date by which the required controls could be installed. For Plant Hammond Units 1-3, an additional analysis was conducted assuming a one year extension is granted under Utility MACT for Hammond as discussed in Section 2.3.4. The set of controls assumed for each unit varies based on what controls are currently expected to be required for compliance with current and future environmental rules and regulations. At the top of each table, there is a list of the controls included in the analysis along with the year in which the control is assumed to be applied for purposes of the analysis.

The incremental cost of the controlled coal unit was compared to a proxy represented by site-specific replacement capacity cost. The evaluation included hourly production cost modeling and cost implications to the transmission system. Changes in production cost, capital, and other fixed costs were captured in the comparison to help determine the most economical option.

5.2 Incremental Costs

Incremental costs include fuel, operation and maintenance ("O&M"), capital, and emissions costs (NO_X, SO_2, and CO_2) associated with continued operation of the facility. An economic dispatch model provided annual fuel costs and emissions costs based on the hourly operation of the unit in each scenario for the years 2011 to 2040.

O&M includes labor, materials, overhead costs, and the costs of engineering and support services requested by the plant. Five-year projections of unit incremental O&M costs were obtained from the 2011 budget process. The incremental costs for the remaining years (2015 to 2040) were calculated using a moving average of the projections for the first 5 years and escalating the resulting value at inflation. Environmental O&M for all scheduled environmental controls is also included.

The incremental capital costs for each unit for years 2011 to 2040 were based on capital expenditures projected by each generating plant. These projected capital expenditures were necessary to keep the units running through the analysis period at the current level of operation.

Environmental control capital expenditures that could be required for compliance were not included in the capital expenditures provided by individual plants. Instead, these incremental capital estimates were provided by Southern Company Services ("SCS") Engineering and Construction Services ("E&CS"). The most recently available capital estimates were used in the studies and were included as specified in the analyses below. The control requirements and dates were based on the interpretation of the combination of currently final, proposed, and/or expected environmental rulemakings and their associated compliance requirements. As these rules are finalized, some of these requirements and dates may shift; however, those included are based on the most recent knowledge and expectations at the time of the analyses.

Fixed costs associated with the continued operation for the existing generating units were based on projections of annual O&M and the net present value ("NPV") of the revenue requirements associated with incremental capital investment necessary to keep the unit operational over the 30-year evaluation period.

5.3 Replacement Costs

Replacement costs, installation capital, fixed O&M, and continue to operate capital are all site specific and developed by SCS E&CS. In addition, individual transmission cost implications of the retirement and replacement were estimated by SCS Transmission.

For the unit retirement studies, most coal units were compared to a proxy represented by the expected cost of a CC at [redacted] This was judged to be the best site in Georgia and was used for comparison on the Plant Branch, Plant Yates and Plant Hammond studies. For the units where fuel was switched to gas with oil backup (Plants Kraft, McIntosh and McManus), a comparison was made to a proxy represented by the expected cost of a site-specific CT. In all comparison studies except Plant Mitchell Unit 4C, the costs of a megawatt ratio portion of the replacement unit was used. For example, if the study looked at replacing 500 MW of coal generation, the costs for a 500 MW portion of a [redacted] MW CC would be used for the comparison.

For Plant Mitchell Unit 4C, because the unit is a small CT that is used exclusively for peaking capacity, the unit was not compared to a replacement CC or CT but instead was compared to a more generic replacement capacity cost.

Replacement energy costs were estimated using the Southern Electric System marginal replacement costs for both continued coal operation and the replacement alternative. Marginal replacement costs were generated with the Pro-Sym® model over a 30-year period (2011 to 2040). The marginal replacement costs were then used to dispatch both the coal unit and the replacement units. The energy benefits (marginal replacement costs minus variable operating costs) were compared to determine the commitment and energy value to the Southern Electric System for both generating options. The net present value of the difference between replacement cost and unit operational cost was calculated to determine the overall net contribution.

In Appendix C Table C.3, the NPV of the revenue requirements for the various components of the replacement generation are provided for each set of coal units studied. These components are included in the calculations for which results are shown in Sections 5.5.1-5.5.10. The NPV of revenue requirements for the controls for each coal unit is provided in Appendix C Table C.2.

5.4 Scenarios

Uncertainty is a challenge for planning. The Company works to manage this challenge by considering multiple different future outcomes in key areas of uncertainty, including future CO_2 control requirements and future natural gas supply. The Company formally analyzes multiple scenarios, each of which adopts a particular view of future CO_2 control and a particular view of future natural gas supply.

With its modeling analysis consultant, Charles River Associates ("CRA"), the Company developed four possible CO_2 control requirement futures and three possible natural gas supply futures. The scenarios created by the combination of these CO_2 and natural gas supply price futures were developed to represent the range of plausible outcomes. Each of the twelve scenarios provides an internally-consistent view of fuel and electricity markets in the US. For each of these scenarios, the Company has performed the detailed asset valuation analysis for each unit discussed in this filing.

Four future CO_2 control scenarios were considered. Each was defined by a different future path of the price of CO_2. The four paths each start in 2015 at $0, $10, $20 and $30 per metric ton of CO_2 (2008$). On each path (except $0), the price increases at [redacted]% annually above inflation. These CO_2 price levels were chosen to span the plausible short term and long term range of CO_2 requirements when considering multiple factors, including US economic impact and likely cost-containment provisions.

Three future natural gas supply scenarios were considered. They largely reflect different views about the future supply of shale and other domestic US natural gas, from relatively plentiful to relatively scarce. Future natural gas demand scenarios were considered. They largely reflect different views about the amount of natural gas-fired generation in the U.S. and consumer and business demand for natural gas. These result in three different price futures for US natural gas, from relatively low to relatively high. These three fuel price scenarios assume long-term supply and demand market equilibrium. In recognition of the normal supply and demand imbalances that actually occur regularly in the natural gas market, the Moderate fuel case also considers volatility surrounding natural gas prices and it reflects recent historic market imbalances price impacts.

Future events related to domestic and global supply and demand may occur within the fuel markets that could result in a range of future price regimes, most importantly in the natural gas markets. These events may or may not be related to ongoing debates within the regulatory or legislative environment, but reflect potential for ranges of fuel supply such as the amount of domestic conventional and unconventional gas (primarily shale gas) available as well as the amount of imports into the U.S., including Liquified Natural Gas ("LNG") and Alaska gas. Therefore, natural gas resource assumptions have been developed describing three scenarios that result in Low, Moderate and High natural gas price forecasts. In addition, supply/demand relationships between coal, oil, and natural gas are reflected within each scenario such that a change in one of these markets impacts the others within the scenario.

The modeling system that CRA employs for the Company's analyses (MRN-NEEM) is a sophisticated, multi-sector dynamic general equilibrium model of the US economy that takes into account supplies and demands for all goods and services in the economy, focusing on the markets for energy and energy-intensive goods and services--especially electricity. The model finds price paths in all markets so that the quantity supplied is equal to the quantity demanded. All of these markets must be considered to generate a fully integrated view in each scenario.

In each scenario, the modeling captures shifts in generation investment choices through retirements of existing capacity (primarily base load coal), installation of new GHG control technologies, and the construction of new replacement capacity. Higher CO_2 and fuel costs generally increase electricity prices and reduce overall US economic activity, therefore, decreasing growth in electricity sales. All of these interrelated factors, including reductions to load growth, are considered in the Company's scenario modeling process.

The detailed asset evaluations also incorporated the twelve fully integrated scenarios in order to capture variations in the operating environments that may affect the retirement of the units. The detailed analyses included the implications of the addition of the following environmental controls where they were deemed to be required: scrubber ("FGD"), SCR, baghouse, potential SNCR, potential CCR regulation costs, scrubber wastewater treatment and compliance with proposed 316(b) regulations.

5.5 Summary of Study Results

The following tables (Sections 5.5.1-5.5.10) present the NPV customer cost results for the comparison of costs of the appropriate replacement proxy unit minus the cost to continue to operate each set of coal units with the controls listed for that particular unit. When a positive value is given for a scenario, there is a net additional cost to the customer for replacement generation and controlling the coal unit is therefore the better economic option. When there is a negative number for a scenario, there is a greater cost to the customer in controlling the coal unit and replacing the coal unit is therefore the better option. Appendix C summarizes the environmental costs applied to each of the controlled coal units. Table C.1 provides the in-service cost of the individual environmental controls. In Table C.2, the NPV of the declining revenue requirements ("DRR") for each of these controls is provided. If the analysis was to be examined without a particular environmental control that *was* included in the results given in Sections 5.5.1-5.5.10, the NPV of the DRR for that particular control could be added back to each scenario. Conversely, if there is an additional required control that was *not* included in the results in Sections 5.5.1-5.5.10, the NPV for the DRR for that control would be subtracted from each cell in the matrix.

Appendix D summarizes the costs and benefits of continued operation for each set of coal units for the \$0 CO_2 – Moderate Fuel case over the 30-year period (2011-2040).

5.5.1 Plant Branch Units 1 & 2

2015 Compliance Results

Customer Costs for Replacement CC Proxy Relative to the Cost of Continued Operation

NPV (2011-2040) in Millions of Dollars

- In-Service Dates of Environmental Controls included on the coal units:

2015 Scrubber ~ 2015 SCR ~ 2015 Baghouse ~ 2017 CCR ~ 2018 Scrubber Wastewater Treatment ~ 2018 Intake Structures

- For the purposes of this analysis, the scrubber, SCR and baghouse were online at the beginning of 2015. Note that this 2015 compliance is in accordance with the original Multipollutant Rule dates of December 31, 2014 for Branch 1 & 2.

Table 5.1

Fuel/CO_2	\$0 CO_2	\$10 CO_2	\$20 CO_2	\$30 CO_2
High	[redacted]	[redacted]	[redacted]	[redacted]
Moderate	[redacted]	[redacted]	[redacted]	[redacted]
Low		[redacted]	[redacted]	[redacted]

In this analysis, the assumed costs include compliance with the Georgia Multipollutant Rule (scrubber and SCR), and anticipated controls under the Utility MACT (baghouse), compliance with EPA's CCR Rule, new effluent guidelines (wastewater treatment), and 316(b) rule (intake structure). Note that a cooling tower was not included in the Plant Branch Units 1 & 2 analysis. The cost for this control is included in Appendix C. Depending on the severity of the 316(b) regulations, the upgrades to the intake structures may be sufficient or a closed cycle cooling tower may be required. Based on the proposed rule, it is expected that a cooling tower would not be required, and therefore costs have not been included. Included in the 316(b) costs is a new intake structure with 20 fine mesh screens with fish returns across the inlet from Little River. These would be required for Plant Branch Units 1 & 2 or Units 3 & 4, regardless of the operation of the other two units and have been included in the analysis.

5.5.2 Plant Branch Units 3 & 4

2015 Compliance Results

Customer Costs for Replacement CC Proxy Relative to the Cost of Continued Operation

NPV (2011-2040) in Millions of Dollars

- In-Service Dates of Environmental Controls included on the coal units:

2015 Scrubber ~ 2015 SCR ~ 2015 Baghouse ~ 2016-2017 CCR ~ 2018 Scrubber Wastewater Treatment ~ 2018 Intake Structures

- For the purposes of this analysis, the scrubber, SCR and baghouse were online at the beginning of 2015. Note that this 2015 compliance is prior to the new Multipollutant Rule dates of late 2015 for Branch 3 & 4.

Table 5.2-a

Fuel/CO_2	\$0 CO_2	\$10 CO_2	\$20 CO_2	\$30 CO_2
High	[redacted]	[redacted]		[redacted]
Moderate	[redacted]	[redacted]	[redacted]	[redacted]
Low	[redacted]	[redacted]	[redacted]	[redacted]

2016 Compliance Results

Customer Costs for Replacement CC Proxy Relative to the Cost of Continued Operation

NPV (2011-2040) in Millions of Dollars

- In-Service Dates of Environmental Controls included on the coal units:

2016 Scrubber ~ 2016 SCR ~ 2016 Baghouse ~ 2016-2017 CCR ~ 2018 Scrubber Wastewater Treatment ~ 2018 Intake Structures

- For the purposes of this analysis, Plant Branch Units 3 & 4 were assumed to be unavailable in 2015 due to required controls not being installed in time to meet anticipated compliance requirements.

Table 5.2-b

Fuel/CO_2	\$0 CO_2	\$10 CO_2	\$20 CO_2	\$30 CO_2
High	[redacted]	[redacted]	[redacted]	[redacted]
Moderate	[redacted]	[redacted]	[redacted]	[redacted]
Low	[redacted]		[redacted]	[redacted]

For both analyses, the assumed costs include compliance with the Georgia Multipollutant Rule (scrubber and SCR), and anticipated controls under the Utility MACT rule (baghouse), compliance with EPA's CCR Rule, new effluent guidelines (wastewater treatment), and 316(b) rule (intake structure). Note that a cooling tower was not included in the Plant Branch Units 3 & 4 analysis. The cost for this control is included in Appendix C. Depending on the severity of the 316(b) regulations, the upgrades to the intake structures may be sufficient or a closed cycle cooling tower may be required. At this time, it is expected that a cooling tower will not be required, and, therefore, costs have not been included. Included in the 316(b) costs is a new intake structure with 20 fine mesh screens with fish returns across the inlet from Little River.

These would be required for Plant Branch Units 1 & 2 or Units 3 & 4, regardless of the operation of the other two units and have been included in the analysis.

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PUBLIC VERSION

TO THE

PUBLIC UTILITIES COMMISSION OF OHIO

DUKE ENERGY OHIO, INC.

2011 ELECTRIC

LONG-TERM FORECAST REPORT

AND RESOURCE PLAN

CASE NO. 11-1439-EL-FOR

STATEMENT
OF
JULIA S. JANSON
PRESIDENT, DUKE ENERGY OHIO, INC.

I, Julia S. Janson, President of Duke Energy Ohio, Inc., hereby certify that the statement and modifications set forth in the 2011 DUKE ENERGY OHIO LONG-TERM ELECTRIC FORECAST REPORT AND RESOURCE PLAN as submitted to the Public Utilities Commission of Ohio are true and correct to the best of my knowledge and belief.

I further certify that the requirements of Ohio Administrative Code §4901:5-1-03, paragraphs (F) to (I) will be met.

Julia S. Janson
President
Duke Energy Ohio, Inc.

Libraries Receiving a Letter of Notification Regarding Duke Energy Ohio, Inc.'s 2011 Long-Term Forecast Report and Resource Plan

County	Library	Address
Adams	Manchester Branch Library	401 Pike St. Manchester, Ohio 45144
Brown	Mary P. Shelton Library	200 West Grant Avenue Georgetown, Ohio 45121
Butler	Lane Public Library	300 North Third Street Hamilton, Ohio 45011
Butler	Middletown Public Library	125 South Broad Street Middletown, Ohio 45044
Clermont	Clermont County Public Library	180 South Third Street Batavia, Ohio 45103
Clinton	Wilmington Public Library	268 North South Street Wilmington, Ohio 45117
Hamilton	Public Library of Cincinnati and Hamilton County University of Cincinnati Library Reference Division	800 Vine Street Cincinnati, Ohio 45202 2600 Clifton Avenue Cincinnati, Ohio 45221
Highland	Highland County District Library	10 Willettsville Pike Hillsboro, Ohio 45133
Montgomery	Dayton and Montgomery County Public Library	215 East Third Street Dayton, Ohio 45402
Preble	Preble County District Library	301 North Barron Street Eaton, Ohio 45320
Warren	Lebanon Public Library	101 South Broadway Lebanon, Ohio 45036

CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of Duke Energy Ohio's Long-Term Forecast Report and Resource Plan was served by hand delivery, this 15th day of July, 2011 upon the following:

Office of the Ohio Consumers' Counsel

10 West Broad Street, Suite 1800

Columbus, OH 43215-3485

Furthermore, a Letter of Notification was sent by First Class U.S. Mail to each library listed in the Report.

Elizabeth H. Watts
Associate General Counsel
Duke Energy Business Services

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L. SYSTEM OPTIMIZER RESOURCE PORTFOLIO ALTERNATIVES

The SO capacity expansion model was used to develop alternative resource portfolios through 2020. There was not a significant difference between the EE economic potential and the requirements associated with SB 221 by 2021. Therefore, only the requirements associated with SB 221 were considered in SO portfolio development. Also, though it is the Company's belief that there will be a carbon-constrained future, the likelihood of legislation being passed prior to 2013 is unlikely. With the uncertainty of federal climate change legislation with regard to greenhouse gas reduction, Duke Energy Ohio has established a CO_2 price curve beginning in 2016 to represent the potential for future federal climate change legislation. The CO_2 prices that Duke Energy is utilizing are associated with proposed and debated legislation, including H.R. 2454 – the American Clean Energy and Security Act of 2009, which passed the U.S. House of Representatives on June 26, 2009. The prices utilized in the 2011 Resource Plan represent the lower end of the range of prices that were estimated in proposed legislation. The projected CO_2 allowance prices are less than $20/ton by 2020 and it is not likely that prices would be higher in the short-term. For this reason, portfolios were not evaluated for variation in CO_2 prices. The primary focus of the resource plan was to determine how best to meet the capacity and energy needs in the 2015 period while positioning the Company to meet AER requirements when fully implemented by 2025.

Sensitivities in load, fuel, and the associated energy prices were evaluated to determine the basis for the different portfolios to be further evaluated in detailed production costing analysis. These portfolios are outlined in Table 4 L.1 below.

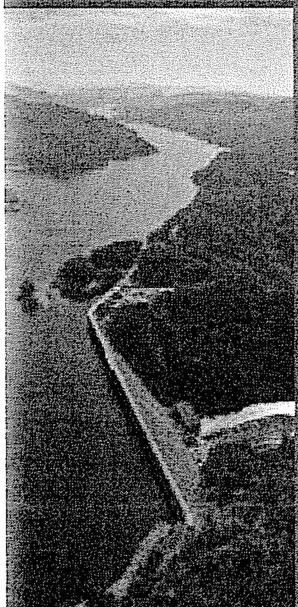
Table 4 L.1

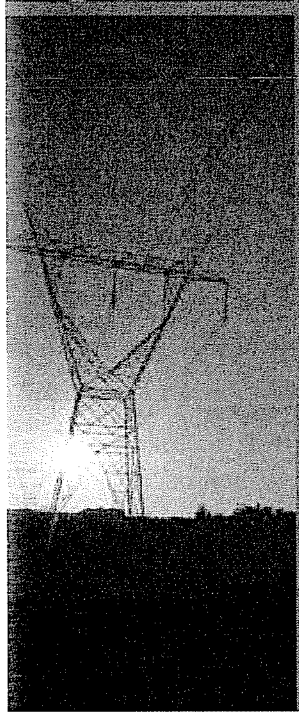
Resource Portfolio Alternatives (2012 – 2020)		
	CT and CC Resources	RPS Renewables
CT Portfolio	1,050 – 2,100 MW Peaking PPA and/or Resources	28 MW new build Solar 350 MW new build Wind
CC/CT Portfolio	1,050 – 1,450 MW Peaking Resource 650 MW CC in 2015	28 MW new build Solar 350 MW new build Wind

The capacity need between 2012 and 2015 averages approximately 1,360 MW per year in addition to capacity that the legacy generation assets will still serve. This need will be met through the Company's FRR plan to meet the 15.3% reserve margin. The capacity need will increase in the 2015 period to 2,261 MWs primarily due to the retirement assumption of Beckjord Units 1-6 (859 MWs). The 2015 timeframe could be volatile time in the capacity market due to the significant number of coal retirements expected due to the new environmental regulatory requirements. Nationwide estimates of retirements of coal generation in the 2015 timeframe fall in the range of 40 to 80 GWs. Depending on the rate of economic recovery and the impact on load growth, adoption rates of DSM, and the number of retired coal units, there could be a capacity shortage in the 2015 timeframe. For this reason, the option of continued operation of and investment in the existing system, coupled with self- build or peaking or intermediate resource purchases is maintained to reduce the risk of exclusively relying on the capacity market to customers.

M. RESOURCE PORTFOLIO ALTERNATIVE EVALUATION RESULTS

After the development of the alternative resource portfolios in SO, the PAR model was used to perform detailed production costing analysis for the CT Portfolio and the CC/CT Portfolio under the Proposed ESP construct for future resource needs.





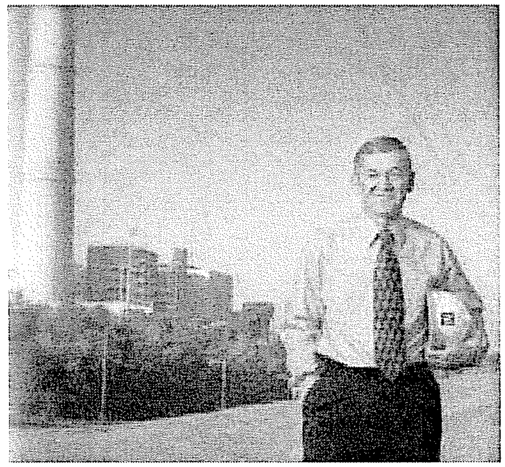
Integrated Resource Plan

TVA's Environmental & Energy Future

March 2011

Message from the CEO

TVA operates one of the largest power systems in the United States. With a generating capacity of more than 34,000 megawatts, we meet the daily electricity needs for an 80,000-square-mile region where more than 9 million people live, work and go to school. That's an enormous responsibility, and one we take very seriously.



A power system large and reliable enough to handle that responsibility doesn't come about by accident. It's the culmination of work by thousands of skilled professionals, and it all starts with focused and detailed planning.

Planning a power system is complex work that involves hundreds of variables, such as consumer trends, fuel and material costs, regulations, technology advancements and the weather. It's complicated even further by the need to forecast needs and conditions decades into the future.

TVA's new integrated resource plan is a critical part of our overall planning effort. It is a comprehensive study of options and strategies and their potential economic and environmental outcomes. The plan was shaped by input from the businesses, industries and regional leaders, as well as ordinary people, whose lives and livelihoods depend on the electricity supplied by TVA. The result of this two-year exercise gives us a sound basis for making better long-term decisions.

In addition, our integrated resource plan will help us fulfill TVA's renewed vision to become one of the nation's leading providers of low-cost and cleaner energy by 2020. The options that have been identified from this process involve reducing TVA's reliance on coal, increasing our supply of nuclear and renewable energy, and working in partnership with local utilities and the people they serve to use energy more efficiently.

Like most things, the cost of electricity is not likely to stay flat in the years ahead. Our challenge will be to keep power affordable while carrying out our vital work with the least impact on the environment today and for future generations.

Tom Kilgore

Tom Kilgore

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3 Public Participation

TVA is the largest public power company in the nation. An objective of this IRP was to understand the needs of the people it serves and how to address those needs in a cost-effective, reliable manner. Since the needs of the people vary, some people are more concerned about the cost of power, some on reliability, while others are concerned about environmental impacts. Therefore, it is TVA's ultimate responsibility to balance these competing needs as it plans for the future.

A transparent and participatory approach was utilized in the development of this IRP. Many opportunities were available to the public that influenced the development – and ultimately the outcome – of this IRP. For example, public briefings and meetings were held across the region, and an advisory review group was created. The following key objectives of public involvement were:

- Engage numerous stakeholders with differing viewpoints and perspectives throughout the entire IRP process
- Incorporate public opinions and viewpoints into the development of the IRP, including activities and opportunities for stakeholders to review and comment on various inputs, analyses and options considered
- Encourage open and honest communication in order to facilitate a sound understanding of the process
- Provide multiple communication channels to provide several ways for members of the public to learn about the IRP process and to provide input

TVA involved the public in each critical step of the IRP process. The involvement helped TVA identify the most effective ways to serve the people of the Tennessee Valley region. Public participation was actively solicited three times during the IRP process.

1. Public scoping period
2. Analysis and evaluation period
3. Draft IRP public comment period

3.1 Public Scoping Period

The TVA IRP process began with a 60-day public scoping period June 15, 2009. TVA announced the start of the process in newspapers throughout the region via media releases and on TVA's website.

In addition, the EPA published the official EIS Notice of Intent in the Federal Register. This notice is required by the NEPA guidelines which require federal agencies such as TVA to prepare an EIS whenever its actions, such as the development of an IRP, have the potential to affect the environment.

Public Comment Process:

Step 1 - Public Scoping Period

- Public Meetings
- Written Comments
- Scoping Questionnaire

Step 2 - Analysis and Evaluation Period

Step 3 - Draft IRP Public Comment Period

During the scoping period, TVA disseminated a broad range of information to the public, including the reasons for developing an IRP, what it would focus on, the process for how an IRP is developed and how the results will be used to guide strategic decision making. Public scoping provided an early and open process to ensure:

- Stakeholder issues and concerns were identified early and properly studied
- Reasonable alternatives and environmental resources were considered
- Key uncertainties that could impact costs or performance of certain energy resources were identified
- Input received was properly considered and would lead to a thorough and balanced final IRP

TVA also reiterated the need to have a balanced approach when considering the tradeoffs of one energy resource for another. While developing this IRP, TVA sought public input on a variety of issues and asked the following questions:

- How will any changes affect system reliability and the price of electricity?
- Should the current power generation mix (e.g., coal, nuclear power, natural gas, hydro, renewable) change?

- Should energy efficiency and demand response be considered in planning for future energy needs?
- Should renewables be considered in planning for future energy needs?
- How can TVA directly affect electricity usage by consumers?

The scoping period helped shape the initial development and framework of this IRP. TVA used the input received to determine what resource options should be considered to meet future demand. TVA used two primary techniques, public meetings and written comments, to collect public input during the scoping period.

3.1.1 Public Meetings

During the scoping period, TVA held seven public meetings across the Tennessee Valley between July 20 and Aug. 6, 2009 (Figure 3-1). The meetings were conducted in an informal, open house format to give participants an opportunity to express concerns, ask questions and provide comments. Exhibits, fact sheets and other materials were available at each public meeting to provide information about the Draft IRP and the associated EIS.

Date	Location
July 20, 2009	Nashville, Tenn.
July 21, 2009	Chattanooga, Tenn.
July 23, 2009	Knoxville, Tenn.
July 28, 2009	Huntsville, Ala.
July 30, 2009	Hopkinsville, Ky.
Aug. 4, 2009	Starkville, Miss.
Aug. 6, 2009	Memphis, Tenn.

Figure 3-1 – Public Scoping Meetings

Attendees included members of the general public, representatives from state agencies and local governments, TVA's congressional delegation representatives, distributors of TVA power, non-governmental organizations and other special interest groups.

Approximately 200 attended the public scoping meetings. TVA subject-matter experts attended each meeting to discuss issues and respond to questions about the IRP planning process and TVA's power system and programs.

3.1.2 Written Comments

During the scoping period, TVA accepted comments via email, fax, letters, TVA's website, public scoping meetings and a scoping questionnaire. At the public scoping meetings, verbal comments were recorded by court reporters and attendees were able to submit written comments by logging onto TVA's website using TVA supplied computers.

Overall, TVA received approximately 1,000 comments from the following communication tools:

- Scoping questionnaire
- Email
- TVA's website
- Public meetings

Comments were received from four federal agencies and 20 state agencies representing six of the seven TVA region states. Some of these responses included specific comments, while others stated they had no comments, but asked to review the Draft IRP and the associated EIS. Figure 3-2 shows the distribution of scoping comments by geographic area.

Some agencies, organizations and individuals provided comments specific to TVA's natural and cultural resource stewardship activities. These comments were not included in the scoping report because they focused on another planning process – TVA's Natural Resource Plan (NRP) and associated EIS. The full scoping report on this IRP as well the NRP can be found on TVA's website.

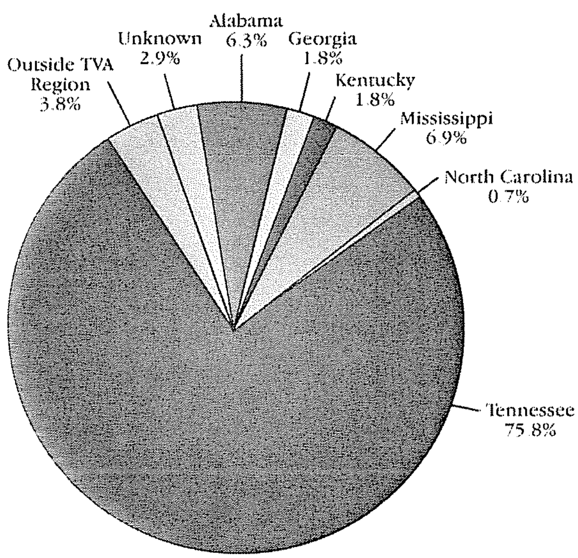


Figure 3-2 – Distribution of Scoping Comments by Geographic Area

3.1.3 Scoping Questionnaire

An 11-part scoping questionnaire was distributed at public meetings and made available on TVA's website. The questionnaire was developed to elicit public opinion on TVA's future generation and efficiency options. At least part of the scoping questionnaire was completed by 845 people, and 640 of the respondents answered the write-in questions as well as the multiple-choice questions.

Many of those who completed the questionnaire expressed a willingness to take various measures to reduce their energy use or pay higher rates for cleaner energy. The willingness to undertake some measures increased with the availability of financial incentives.

After further analysis, the results of the questionnaire indicated that the findings were not statistically significant and the survey population was not fully representative of the entire Tennessee Valley region. Therefore, TVA decided to conduct a phone survey of approximately 1,000 individuals across the entire region in the summer of 2010.

3.2 Analysis and Evaluation Period

The analysis and evaluation period took key themes and results identified from the scoping period and developed the framework for analysis and evaluation. The findings were considered when TVA developed the range of strategies for IRP analysis.

During this phase, TVA used the following three techniques to collect public input:

1. Stakeholder Review Group
2. Public briefings
3. Phone survey

Public Comment Process:

Step 1 - Scoping Period

Step 2 - Analysis and Evaluation Period

- Stakeholder Review Group
- Public Briefings
- Phone Survey

Step 3 - Draft IRP Public Comment Period

3.2.1 Stakeholder Review Group

Early in the IRP process, TVA recognized it would be difficult to get specific and continuous input from the public beyond the scoping period. To obtain more in-depth, ongoing input from the public, TVA established an advisory Stakeholder Review Group (SRG) in July 2009.

The formation of this diverse 16-member review group (listed on page 42) was the cornerstone of the public input process. It consisted of representatives from business and industry, state agencies, government, distributors of TVA power, academia, special interest groups and civic organizations. In addition to providing their individual views to TVA, SRG members represented their constituency and reported to them on the IRP process.

The SRG met approximately every month with TVA. Ten meetings were held prior to the release of the Draft IRP and the associated EIS at various locations throughout the region. Five additional meetings were held between the release of the Draft IRP and approval of the Recommended Planning Direction to facilitate ongoing feedback and guidance for this IRP. Figure 3-3 shows the dates and locations of all the SRG meetings.

Date	Location
July 29, 2009	Nashville, Tenn.
Aug. 18, 2009	Knoxville, Tenn.
Sept. 24, 2009	Chattanooga, Tenn.
Oct. 22 & 23, 2009	Chattanooga, Tenn.
Dec. 10 & 11, 2009	Nashville, Tenn.
Feb. 17, 2010	Knoxville, Tenn.
May 13, 2010	Knoxville, Tenn.
June 29, 2010	Murfreesboro, Tenn.
July 20 & 21, 2010	Chattanooga, Tenn.
Aug. 12, 2010	Chattanooga, Tenn.
Aug. 26, 2010	Chattanooga, Tenn.
Oct. 28, 2010	Knoxville, Tenn.
Nov. 18, 2010	Murfreesboro, Tenn.
Dec. 15, 2010	Chattanooga, Tenn.
Jan. 26, 2011	Knoxville, Tenn.
Feb. 24, 2011	Chattanooga, Tenn.

Figure 3-3 – Stakeholder Review Group Meetings

The meetings were designed to encourage dialogue on all facets of the IRP process, and to facilitate information sharing, collaboration and expectations for this IRP. Topics included energy efficiency best practices, TVA's power delivery structure, load and commodity forecasts and supply resource options.

The individual views of SRG members were collected on the entire range of assumptions, analytical techniques and proposed energy resource options and strategies. Given the diverse makeup of the SRG, there were a wide range of views on specific issues, such as the value of energy efficiency programs, environmental concerns and the appropriateness of some new technologies. Open discussions supported by the best available data facilitated better comprehension of the specific issues.

To increase public access and transparency to the IRP process, all non-confidential SRG meeting material (i.e., presentations, agenda and minutes) was posted on TVA's website. In addition, TVA developed an internal website specifically for SRG members to post information on and to request data from TVA staff.

3.2.2 Public Briefings

In addition to the public scoping and SRG meetings, TVA held four public briefings (Figure 3-4). The public briefings informed the general public of the IRP process.

Date	Location
Oct. 23, 2009	Chattanooga, Tenn.
Nov. 16, 2009	Chattanooga, Tenn.
Feb. 17, 2010	Knoxville, Tenn.
May 13, 2010	Knoxville, Tenn.

Figure 3-4 – Public Briefings

Participants had the option to attend in person or by webinar. The format of the public briefings included a brief presentation followed by a moderated Q&A session with the audience.

Topics discussed at the public briefings included an overview of the integrated resource planning process, resource options, development of scenarios and strategies and evaluation metrics.

The public briefings attendance averaged 15 to 20 in-person participants and approximately 30 to 40 participants by webinar. Videos of the briefings and presentation materials were posted on the IRP project website.

TVA also briefed the public on the IRP process through presentations given at local organizations, clubs and associations including the following:

- Association of Energy Engineers
- Tennessee Renewable Energy and Economic Development Council
- Chattanooga Engineers Club
- City of Chattanooga
- Chattanooga Green Spaces
- EPRI Environmental Aspects of Renewable Energy Interest Group Workshop
- Clean Energy Speakers Series at Georgia Tech
- Howard H. Baker, Jr. Center for Public Policy
- Technical Society of Knoxville

3.2.3 Phone Survey

To ensure an even wider representation of opinions on IRP choices were considered, TVA partnered with Harris Interactive to develop a statistically representative phone survey of approximately 1,000 Tennessee Valley residents. The customer phone survey was conducted during June and July 2010 for the following reasons:

- Determine primary power generation concerns among the Tennessee Valley residents (i.e., cost, reliability, use of renewables, etc.)
- Determine market potential for voluntary and financially incentivized energy efficiency programs
- Determine market potential of renewable programs, including Green Power Switch® and other existing or planned energy efficiency and demand response programs
- Estimate potential market pricing for renewable power programs, including the additional amounts Tennessee Valley residents are willing to pay each month for energy from renewable sources
- Assess Tennessee Valley residents' attitudes of and satisfaction with TVA, including analysis of the services that it provides to the Tennessee Valley

Survey results indicated that the Tennessee Valley residents have a favorable attitude of TVA, consider system reliability a critical component of utility services and want to see TVA focused on keeping prices affordable.

Key findings included:

TVA quality of service	• 94 percent of respondents agreed that providing a reliable supply of electricity is very important in assessing TVA's quality of service • 92 percent indicated that keeping electricity rates affordable is important
Meeting future energy needs	• 70 percent of respondents also deemed it very important for TVA to reduce air pollutants and emissions

Renewable energy	• 42 percent of respondents believed that adding different energy sources, such as solar and wind, into TVA resource portfolio should be emphasized the most to meet future energy needs
	• 42 percent of respondents indicated they likely would pay more for renewable energy, with the following breakdown:
	  ◦ Those indicating they would definitely pay more would pay an average of $12.60 per month to ensure that 10 percent of their energy comes from renewable sources
	  ◦ This same group would pay an average of $26.91 more per month to ensure that all of their energy is renewable
	  ◦ Tennessee Valley residents indicating they would definitely or probably pay more were willing to pay $11 to $20 per month to reduce CO_2 emissions
	  ◦ Opportunities exist for additional Green Power Switch® awareness among Tennessee Valley residents

Biggest concerns related to electricity production	• Cost and billing • Environmental impact • Quality of power supply

3.3 Draft IRP Public Comment Period

After the Draft IRP was completed in the fall of 2010, TVA provided an opportunity for the public to provide comments and give input. Following the Sept. 15, 2010 publication of the Draft IRP with EPA, a 52-day comment period was provided to solicit input about the Draft IRP from the public.

Originally set to close Nov. 8, 2010, the 45-day comment period was extended an additional seven days to accommodate several external stakeholders' requests. For this phase of the IRP process, TVA presented the results to both internal TVA stakeholders and the general public in the Draft IRP and the associated EIS.

Public Comment Process:

Step 1 - Scoping Period

Step 2 - Analysis and Evaluation Period

Step 3 - Draft IRP Public Comment Period

- Public Meetings
- Webinars
- Written Comments

TVA used the following three techniques to collect input during the Draft IRP:

1. Public meetings
2. Webinars
3. Written comments

3.3.1 Public Meetings

TVA had five meetings with the public across the Tennessee Valley region in October 2010 (Figure 3-5). These meetings gave the public an opportunity to present their views on the Draft IRP to TVA leadership and subject-matter experts.

Date	Location
Oct. 5, 2010	Bowling Green, Ky.
Oct. 6, 2010	Nashville, Tenn.
Oct. 7, 2010	Olive Branch, Miss.
Oct. 13, 2010	Knoxville, Tenn.
Oct. 14, 2010	Huntsville, Ala.

Figure 3-5 – Public Comment Period Meetings

TVA publicized the meetings and webinars by placing advertisements in major newspapers and issuing news releases prior to each meeting that many local newspapers carried. Before each of the meetings, TVA met with local reporters in each location who frequently write about TVA and the IRP process so that they, in turn, could write articles to help the public understand the IRP process and draft document.

Online advertising (i.e., announcements on TVA's Facebook page) was used to reach an even wider audience. TVA's website was also regularly updated with the latest news regarding the IRP process and logistics for each public meeting.

At each of these meetings, TVA presented an overview of the Draft IRP followed by a moderated Q&A session supported by a panel of TVA subject-matter experts. Attendees were able to address comments or questions to the panel. Attendees also had the option to submit written and verbal comments to a court reporter before or after the presentations. A transcript and video of each meeting was recorded. The presentation slides and video of the meeting in Bowling Green, Ky., and videos of each Q&A session were posted on the TVA's website.

TVA encouraged comments from the public on the Draft IRP and the associated EIS. Comments received enabled TVA staff to identify public concerns and recommendations concerning the future operation of the TVA power system. The public comments and TVA's responses are included in the associated EIS.

3.3.2 Webinars

To encourage as much participation as possible, members of the public who were not able to attend public meetings were able to participate by webinar. Attendees registered in advance and were able to access the presentation and participate in the Q&A session from personal computers.

3.3.3 Written Comments

During the 52-day public comment period, comments were submitted via TVA's website, email, U.S. mail and fax. Comments and questions recorded at each of the public meetings were also considered.

In all, TVA received approximately 500 responses from a multitude of individuals, organizations and agencies. These responses contained 748 comments of which 372 were unique and addressed in the associated EIS. A general summary of unique comments received during the public comment period on the Draft IRP can be seen in Figure 3-6.

Method of Comment	Number Received
Email	38
Online comment form	104
Webinar comment/question from IRP meetings	16
Oral comment/question from IRP meetings	30
Letters	16
Form Letters (pre-printed post cards)	297
Total	501

Figure 3-6 – Type of Responses Submitted

The following organizations and agencies submitted comments:

- Environmental Protection Agency
- Natural Resource Defense Council
- Southern Alliance for Clean Energy
- Sierra Club
- Earth Justice
- Distributors of TVA power
- State agencies
- Tennessee Valley Public Power Association
- Industry groups (i.e., solar energy, natural gas, etc.)

3.4 Public Input Received During the IRP Process

Public input received during the IRP process covered a wide spectrum of subjects. From public scoping to the comments received on the Draft IRP, the ongoing feedback assisted TVA in identifying the relevant concerns of the public with respect to resource planning. Input received during the IRP process also provided beneficial insight to common public perceptions of TVA programs and willingness to invest in certain resource options. For example, the SRG and public input encouraged TVA to consider larger renewable portfolio targets beyond current resource plans, resulting in consideration of portfolios of 2,500 and 3,500 MW.

Moreover, public input helped develop the framework for analysis and addressed a wide range of issues, including the cost of power, recommended resource options, the environmental impacts of different resource options and the integrated resource planning process. The following sections briefly summarize the issues raised with additional detail provided in the associated EIS.

Costs of New Capacity, Financing Requirements and Rate Implications

Concerns about the ability of TVA to design, build and deliver major new capacity on time and within budget were expressed. Questions about the validity of construction cost estimates for new nuclear capacity were raised.

The public also expressed concerns about TVA's ability to fund future resource additions due to the $30 billion limit on TVA's statutory borrowing authority. TVA's financing options to cover the costs of construction for major capital investments are limited to borrowing, increasing rates or other less traditional forms of financing. There were also concerns about potential impacts on short-term rates. However, some believed that higher rates may promote energy efficiency investments.

While a large number of people were opposed to any future price increases, a number of those who completed the scoping questionnaire expressed a willingness to pay $1-$20 more per month for TVA to increase generation from non-greenhouse gas emitting sources.

Recommended Energy Resource Options

The public made recommendations about TVA's future supply- and demand-side resource options. TVA's future resource portfolio should:

- Avoid or minimize rate increases
- Minimize or reduce pollution and other environmental impacts
- Maximize reliability
- Contain a diversity of fuel sources

The following resources options were mentioned:

Nuclear expansion	• Supported nuclear additions if implemented in a cost-effective, responsible way • Concerned with rising costs and nuclear waste issues related to additions to the nuclear portfolio
EEDR initiatives	• Pleased with the contribution of EEDR in the planning strategies retained in the Draft IRP • Comments regarding the target level of EEDR being studied and the potential for larger amounts of EE to displace new nuclear capacity • Uncertainty about cost, lost revenue impacts and program effectiveness; and questioned measurement and verification of benefits
Renewable additions	• Supported increased renewable generation (including wind, solar, locally-sourced biomass and low-impact hydro) as long as costs are competitive • Stated the need for a stronger commitment to developing renewables within the Tennessee Valley region, particularly solar, as opposed to imported wind power • Questioned system operational impacts caused by intermittent or off-peak resources (i.e., wind and solar)
Idling coal-fired capacity	• Commended TVA on the strategy for coal-fired capacity idling and to consider larger quantities of idled capacity • Concerned with the economic and environmental implications of idling certain coal-fired units • Concerned about TVA's risk exposure for pending carbon legislation and issues related to lead-time for positioning coal-fired assets for idling, retirement and/or return to service
Energy storage	• Recommended an increase in energy storage capability
Natural gas	• Supported additional natural gas-fired generation

Environmental Impacts of Power System Operations

A general concern about pollution was a frequently mentioned issue in regards to the TVA power system. Additionally, much of the public felt the issues with air pollutants, greenhouse gas emissions, climate change, spent nuclear fuel and coal combustion by-products were of high importance.

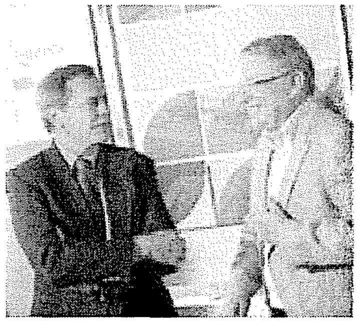
Many comments encouraged TVA to decrease its emissions of greenhouse gases while others questioned the human influence on climate change. The issue was also raised of the impacts of buying coal from surface mines, particularly mountaintop removal mines, and recommended that TVA stop this practice. The Kingston Fossil Plant ash spill in December 2008 was frequently mentioned.

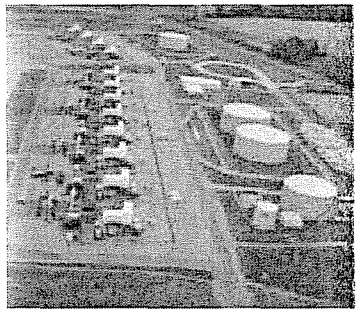
The Integrated Resource Planning Process

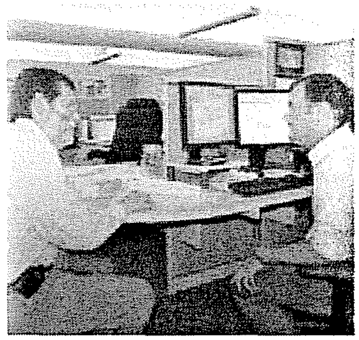
Several people addressed the IRP process. Their comments recommended that TVA continue to follow industry standard practices; enter the process without preconceptions about the adequacy of various resource options; be open and transparent throughout the planning process; treat energy efficiency and renewable energy as priority resources and address the total societal costs and benefits.

3.5 Response to Public Input and Comments

Input received from the general public and stakeholders was a key part of the IRP process. Listening to different stakeholders' perspectives, viewpoints and sometimes competing objectives played a prominent role in choosing a Recommended Planning Direction for TVA. Appendix F – Stakeholder Input Considered and Incorporated provides examples on how key themes were incorporated into the IRP analysis.

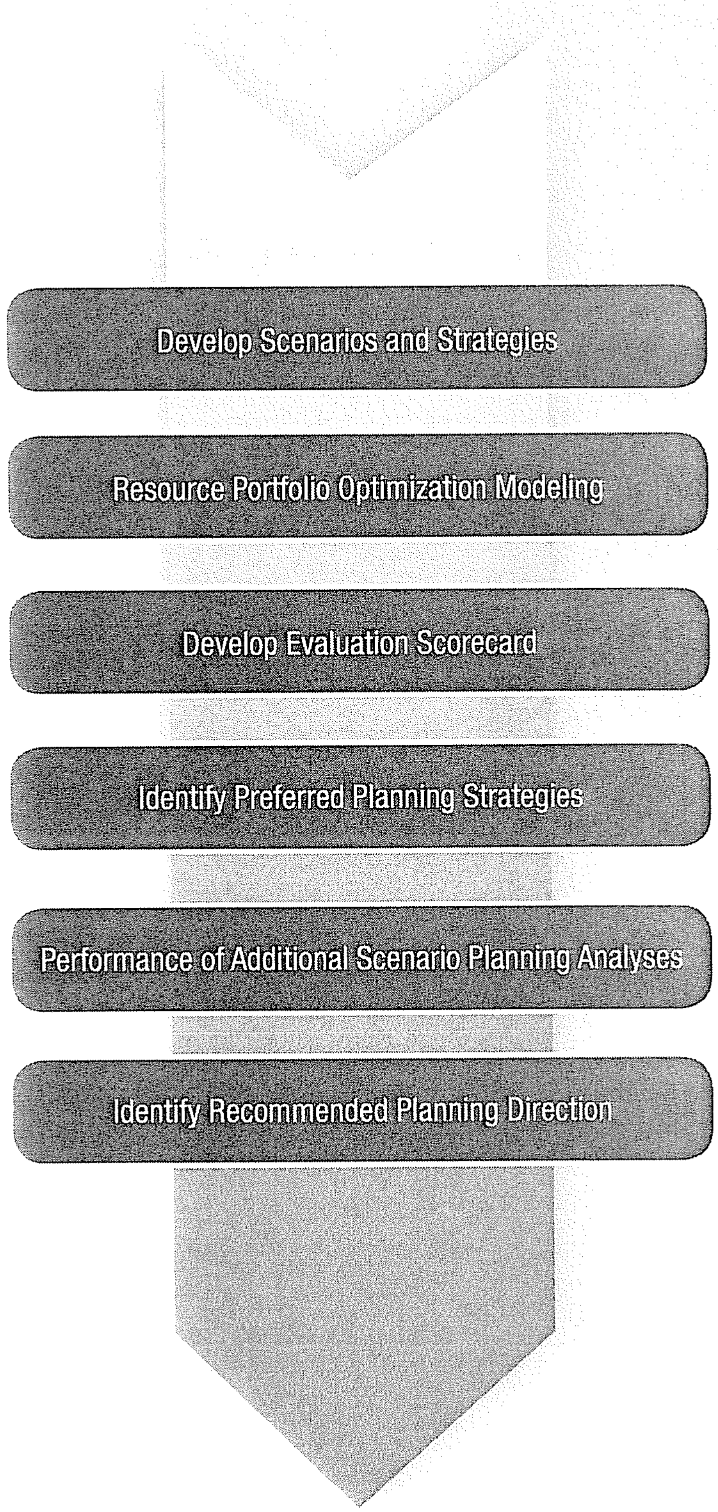






TVA's Integrated Resource Plan is a synthesis of public input and strategic planning and professional analysis.

Process for Identifying the Recommended Planning Direction



6 Resource Plan Development and Analysis

TVA employed a scenario planning approach in the development of the Draft and the final IRP. This approach is commonly used in the utility industry. The goal of this approach was to develop a "no-regrets" strategy that was relatively insensitive to uncertainty. In other words, once strategic decisions were made, the strategy would perform well regardless of how the future unfolds. The processes used in the scenario planning approach, including evaluation methods and strategy selection, are outlined in this chapter.

This chapter describes the following six steps of the Draft IRP process:

1. Development of the scenarios and strategies used to conduct the scenario planning analysis
2. Resource portfolios optimization modeling
3. Development of scenario planning scorecards to measure the performance of the portfolios and strategies developed in the scenario planning analysis
4. Identification of preferred planning strategies for publication in the Draft IRP
5. Incorporation of public input and performance of additional scenario planning analyses
6. Identification of the Recommended Planning Direction

6.1 Development of Scenarios and Strategies

Scenario planning is useful for determining how various business decisions will perform in an uncertain future. Multiple strategies, which represented business decisions that TVA can control, were modeled against multiple scenarios, which represented uncertain futures that TVA cannot control. The intersection of a single strategy and a single scenario resulted in a resource portfolio.[1] A portfolio is a 20-year capacity expansion plan that is unique to that strategy and scenario combination.

Modeling multiple strategies within multiple scenarios resulted in a large number of portfolios. Proper analysis of these portfolios was a challenge. Accordingly, during early stages of the analysis, it was more important to observe trends or common characteristics that strategies exhibited over multiple scenarios rather than focusing on specific outcomes in individual portfolios. If a strategy behaved in a similar manner in most scenarios, the modelers could be confident of its robustness. Characteristics of robustness included increased flexibility, less risk over the long term and the ability to mitigate the impacts of

[1]Portfolios are also referred to as capacity expansion plans or resource portfolios

uncertainty. Conversely, a strategy that behaved differently or poorly in each scenario that it was modeled within was considered more risky and indicated a higher probability for disappointment and future regret.

6.1.1 Development of Scenarios

Most quantitative models focus on what is statistically likely based on history, market data and projected future patterns. The scenarios developed for the planning approach operated differently by utilizing assumptions that the future evolves along paths not suggested by history. They were not assigned a probability that one particular future is more likely to occur than another. Using this approach, scenarios identified and framed plausible futures that were studied in the development of the long-range resource plan.

The following three-step process was used to develop scenarios used in this IRP:

1. Identification of key uncertainties
2. Development of scenarios
3. Determination of scenario uncertainty values

Scenarios represent future conditions that TVA cannot control but must adapt to.

Identification of Key Uncertainties

TVA, with input from the SRG, identified uncertainties that were used as building blocks to develop scenarios for this IRP. The key uncertainties are listed in Figure 6-1.

Key Uncertainty	Description
Greenhouse gas (GHG) requirements	• Reflects level of emission reductions (CO_2 and other GHG) mandated by federal legislation plus the cost of carbon allowances
Environmental outlook	Changes in regulations addressing: • Air emissions (exclusive of GHG) • Land • Water • Waste
Energy efficiency and RES	• Reflects mandates for minimum generation from renewables and the viability of renewable generation sources • It includes the percentage of the RES standard that can be met with energy efficiency
Total load	• Reflects variance of actual load to what is forecast • Accounts for benefits of EEDR penetration
Capital expansion viability & costs	For nuclear, fossil, other generation and transmission, includes risks associated with: • Licensing • Permitting • Project schedule
Financing	• Financial cost (interest rate) of securing capital
Commodity prices	• Includes natural gas, coal, oil, uranium and spot price of electricity
Contract purchase power cost	• Reflects demand cost, availability of power and transmission constraints
Change in load shape	Includes effects of factors such as: • Time-of-use rates • Plug-in Hybrid Electric Vehicles (transportation) • Distributed generation • Economics changing customer base • Energy storage • Energy efficiency • Smart grid / demand response
Construction cost escalation	Includes the following for nuclear, fossil and other generation: • Commodity cost escalation • Labor and equipment cost escalation

Figure 6-1 – Key Uncertainties

Development of Scenarios

Scenarios were constructed by utilizing various combinations of the key uncertainties in Figure 6-1. They were then further refined to ensure that the following characteristics for each scenario:

- Represented a plausible, meaningful future "world" (e.g., uncertainties related to cost, regulation and environment)
- Were unique among the scenarios being considered for study
- Reflected a future that TVA could find itself in during the timeframe studied in this IRP

- Placed sufficient stress on the resource selection process
- Provided a foundation for analyzing the robustness, flexibility and adaptability of each combination of various supply- and demand-side options
- Captured relevant key stakeholder interests

A summary of the scenarios selected for the IRP analysis is shown in Figure 6-2. During the scoping phase in summer 2009, Scenarios 1 through 6 were developed for use in the Draft IRP analysis. Scenario 7 was also developed as a reference case in the Draft IRP. It closely resembled TVA's long-term planning outlook at the time the original scenarios were developed. Another reference case, Scenario 8 was added after the publication of the Draft IRP. It captured the impacts of the recent recession and was used in subsequent analysis.

Scenario	Key Characteristics
1 Economy Recovers Dramatically	• Economy recovers stronger than expected and creates high demand for electricity • Carbon legislation and renewable electricity standards are passed • Demand for commodity and construction resources increases • Electricity prices are moderated by increased gas supply
2 Environmental Focus is a National Priority	• Mitigation of climate change effects and development of a "green economy" is a priority • The cost of CO_2 allowances, gas and electricity increase significantly • Industry focus turns to nuclear, renewables, conservation and gas to meet demand
3 Prolonged Economic Malaise	• Prolonged, stagnant economy results in low to negative load growth and delayed expansion of new generation • Federal climate change legislation is delayed due to concerns of adding further pressure to the economy
4 Game-changing Technology	• Strong economy with high demand for electricity and commodities • High price levels and concerns about the environment incentivize conservation • Game-changing technology results in an abrupt decrease in load served after strong growth
5 Energy Independence	• The U.S. focuses on reducing its dependence on non-North American fuel sources • Supply of natural gas is constrained and prices for gas and electricity rise • Energy efficiency and renewable energy move to the forefront as an objective of achieving energy independence
6 Carbon Regulation Creates Economic Downturn	• Federal climate change legislation is passed and implemented quickly • High prices for gas and CO_2 allowances increase electricity prices significantly • U.S. based energy-intensive industry is non-competitive in global markets and leads to an economic downturn
7 Reference Case: Spring 2010	• Economic growth lower than historical averages • Carbon legislation is passed and implemented by 2013 • Natural gas and electricity prices are moderate
8 Reference Case: Great Recession Impacts Recovery	• Economic outlook includes economic recovery, but growth is at a slightly lower rate than Scenario 7 due to lingering recession impacts • Natural gas prices are lower to reflect recent market trends

Figure 6-2 – Scenarios Key Characteristics

Determination of Scenario Uncertainty Values

Once each of the key uncertainties were defined, specific numerical values for each aspect of the scenarios were developed utilizing the following assumptions:

- Climate change uncertainty will be based upon stringency of requirements and timeline required for compliance and cost of CO_2 allowances
- An aggressive EPA regulatory schedule is expected to create additional compliance requirements (e.g., Hazardous Air Pollutants Maximum Achievable Control Technology [HAPs MACT], revised ambient air standards, etc.)
- Command and control regulations for HAPs MACT will likely drive plant-by-plant compliance
- RES will help accomplish GHG reduction required at the federal level
- The spot price of electricity will be correlated with the price of natural gas and coal
- Demand, primarily driven by economic conditions, will be affected by energy efficiency, demand response and other factors
- Schedule risk will be related to demand as well as the uncertainty of permitting and licensing generation and transmission projects
- Economic conditions and associated inflationary pressures will become the primary drivers for changes in financing costs
- Construction costs will be driven by demand as well as availability of labor, equipment, design and raw materials
- Economic conditions will become the primary driver, but the legislative/regulatory environment will apply additional pressure by introducing uncertainty related to potential schedule impacts
- Cost and availability of contract power purchases will be primarily driven by economic conditions and local area demand (i.e., load growth)

A detailed description of each scenario's uncertainty values is shown in Figure 6-3.

Uncertainty	Scenario 1 Economy Recovers Dramatically	Scenario 2 Environmental Focus is a National Priority	Scenario 3 Prolonged Economic Malaise	Scenario 4 [illegible]	Scenario 5 Energy Independence	Scenario 6 Carbon Legislation Creates Economic Downturn	Scenario 7 Reference Case: Spring 2010	Scenario 8 Reference Case: Great Recession Impacts Recovery
GHG requirements	CO_2 price \$27/ton (\$30/metric ton) in 2014 and \$82 (\$90/metric ton) by 2030. 77% allowance allocation, 41% by 2030	CO_2 price \$17/ton (\$19/metric ton) in 2012 and \$94 (\$104/metric ton) by 2030. 77% allowance allocation 28% by 2030	No federal requirement (CO_2 price = \$0/ton)	CO_2 price \$18/ton (\$20/metric ton) in 2013 and \$45 (\$50/metric ton) by 2030. 77% allowance allocation, 41% by 2030	CO_2 price \$18/ton (\$20/metric ton) in 2013 and \$45 (\$50/metric ton) by 2030. 77% allowance allocation, 41% by 2030	CO_2 price \$17/ton (\$19/metric ton) in 2012 and \$94 (\$104/metric ton) by 2030. 77% allowance allocation, 28% by 2030	CO_2 price \$15/ton (\$17/metric ton) in 2013 and \$56 (\$62/metric ton) by 2030. 77% allowance allocation, 39% by 2030	Same as Scenario 7
Environmental outlook	Same as Scenario 7	SO_2 controls 2017 NO_x controls Dec 2016 Hg MACT 2014 HAP MACT 2015	No additional requirements (CAIR requirements, with no MACT requirements)	Same as Scenario 7	Same as Scenario 7	Same as Scenario 7	SCR all units by 2017 FGD all units by 2018 HAPs MACT by 2015	Same as Scenario 7
Energy efficiency and RES	RES – 3% by 2012, 20% by 2021 (adjusted total retail sales) EE can meet up to 25% or requirement	RES – 5% by 2012, 30% by 2021 (adjusted total retail sales) EE can meet up to 25% or requirement	No federal requirement	RES – 5% by 2012, 20% by 2021 (adjusted total retail sales) EE can meet up to 40% or requirement	RES – 5% by 2012 20% by 2021 (adjusted total retail sales) EE can meet up to 40% or requirement	RES – 5% by 2012, 30% by 2021 (adjusted total retail sales) EE can meet up to 25% or requirement	RES – 3% by 2012 15% by 2021 (adjusted total retail sales) EE can meet up to 25% or requirement	Same as Scenario 7
Total load	Med grow to High by 2015; High Dist; Alcoa Returns in 2010+; USEC stays forever; Dept Dist same as *Scenario 7*	Medium case, then 2012 40% rate increase; Low Dist; DS customer reductions (steel/paper plants); USEC stays forever; *Dept Dist same* as Scenario 7	Low load case; Low Dist; Alcoa not returning. No HSC & Wacker; USEC leaves June 2013; Dept Disc *same as Scenario 7*	Med-High load growth through 2020, then 20% decrease 2021-2022 including USEC departure, reduced dist sales & extended TOU	Medium case, then 20% rate increase in 2014; unrestricted PHEV included; TOU	Medium load case 2010-2011; 2012 low case then flat w/no growth; USEC leaves 2013; Alcoa not returning. HSC & Wacker not in; TOU	Moderate growth	Moderate to low growth
Capital expansion viability & costs	Moderate schedule risk	High schedule risk	Low schedule risk	Moderate schedule risk	Moderate schedule risk	Low schedule risk	Moderate schedule risk	Moderate schedule risk
Financing	Higher than Scenario 7 – higher inflation due to higher economic growth	Higher than Scenario 7 – higher inflation due to looser monetary policy supporting economic growth	Lower than Scenario 7 – lower inflation due to lower economic growth	Same as Scenario 7 – increased productivity due to technology leads to stronger economic wealth and non-inflationary money growth	Higher than Scenario 7 – higher inflation due to looser monetary policy supporting economic growth	Lower than Scenario 7 – lower inflation due to lower economic growth	Based on current borrowing rate	Based on current borrowing rate
Commodity prices	Gas & coal higher than Scenario 7	Gas higher, coal lower than Scenario 7	Gas much lower & coal much higher than Scenario 7	Gas lower & coal slightly higher than Scenario 7	Gas & coal higher than Scenario 7	Gas & coal much lower than Scenario 7	Gas - \$6-8/mmBTU Coal - \$40/ton	Gas - \$5-7/mmBTU Coal - \$40/ton
Contract purchase power cost	Much higher cost & lower availability	Higher cost & lower availability	Same as Scenario 7, then much lower cost with high availability	Higher cost & lower availability, then much lower cost with high availability after load decrease	Higher cost & lower availability	Lower cost with high availability	Moderate cost & availability	Moderate cost & availability
Construction cost escalation	Much higher than Scenario 7 – high economic growth causes high demand for new plants and high escalation rate	Somewhat higher than Scenario 7 – due to "construction costs escalating at high rate due to large volume of nuclear, renewables and env controls projects" High regulatory scrutiny adds to project costs	Lower than Scenario 7 – low load growth leads to low escalation	This scenario has two stages of escalation: 1) higher than Scenario 7 due to high load growth early, then 2) lower escalation when game-changing technology hits	Somewhat higher than Scenario 7 – moderately strong economy and load growth leads to somewhat higher than base escalation	Lower than Scenario 7 – negative load growth, very weak economy and high renewables lead to low escalation	Moderate escalation	Moderate escalation

Figure 6-3 – Scenario Descriptions

6.1.2 Development of Planning Strategies

After development of the scenarios, planning strategies were designed to test the various business decisions and portfolio choices that TVA has control over and might consider. Strategies are very different from the scenarios. Whereas, scenarios describe plausible futures and include factors that TVA cannot control, strategies describe business decisions over which TVA has full control. In the end, a well-designed strategy would perform well in many possible scenarios whereas a poorly designed strategy would frequently not perform well.

The following three-step process was used to design the strategies in this IRP:

1. Identification of key components
2. Development of strategies using key components
3. Definition of strategy

Planning strategies represent decisions and choices over which TVA has full control.

Identification of Key Components

To define the planning strategies, nine distinct categories of components were identified. The choice of components was influenced by comments received during the public scoping period and input from the SRG. Comments stated that TVA should challenge its targets for EEDR and renewables beyond the current portfolios. Accordingly, the ranges for both components were significantly expanded. The components for the planning strategies are described in Figure 6-4.

Component	Description	Type
EEDR portfolio	The level of EEDR included in each strategy	Defined Model Input
Renewable additions	The amount of renewable resources added in each strategy	Defined Model Input
Coal-fired capacity idling	A proposed schedule of coal-fired unit idling that will be tested in each strategy	Defined Model Input
Energy storage	Option to include a pumped-storage unit in selected strategies	Defined Model Input
Nuclear	Constraints related to the addition of new nuclear capacity	Constraint
Coal	Limitations on technology and timing for new coal-fired plants	Constraint
Gas-fired supply (self-build)	Limitations on gas-fired unit expansion	Constraint
Market purchases	Level of market reliance allowed in each strategy	Constraint
Transmission	Type and level of transmission infrastructure required to support resource options in each strategy	Constraint

Figure 6-4 – Components of Planning Strategies

As noted in Figure 6-4, there were two types of components, used in the model.

Defined model inputs	These components were scheduled or predetermined. This applied to both the timing and the quantity of specific asset decisions
Constraints in the model optimization	These components constrained the optimization of asset choices such as minimum build times, technology limitations and other strategic constraints including limits on market purchases. The capacity optimization model selected resources that were consistent with these constraints

Development of Strategies Using Key Components

TVA combined these nine components and created five distinct planning strategies for the Draft IRP analysis. Figure 6-5 lists the five distinct planning strategies and their key characteristics.

Planning Strategy	Key Characteristics
A Limited Change in Current Resource Portfolio	• Retain and maintain existing generating fleet (no additions beyond Watts Bar Unit 2) • Rely on the market to meet future resource needs
B Baseline Plan Resource Portfolio	• Allows for nuclear expansion after 2018 and new gas-fired capacity as needed • Assumes idling of approximately 2,000 MW of coal-fired capacity • Includes EEDR portfolios and wind PPAs
C Diversity Focused Resource Portfolio	• Allows for nuclear expansion after 2018 and new gas-fired capacity as needed • Increases the contribution from EEDR portfolio and new renewables • Adds a pumped-storage unit • Assumes idling of approximately 3,000 MW of coal-fired capacity
D Nuclear Focused Resource Portfolio	• Allows for nuclear expansion after 2018 and new gas-fired capacity as needed • Includes an increased EEDR portfolio compared to other strategies • Assumes idling of approximately 7,000 MW of coal-fired capacity • Includes new renewables (same as Strategy C) • Includes a pumped-storage unit
E EEDR and Renewables Focused Resource Portfolio	• Assumes greatest reliance on EEDR portfolio of any strategy and includes largest new renewable portfolio • Assumes idling of approximately 5,000 MW of coal-fired capacity • Delays nuclear expansion until 2022

Figure 6-5 – Planning Strategies Key Characteristics

Definition of Strategy

Once each strategy's key characteristics were defined, specific numerical values for each component of each strategy were defined as shown in Figure 6-6.

Components	Strategy A Limited Change in Current Resource Portfolio	Strategy B Baseline Plan Resource Portfolio	Strategy C Diversity Focused Resource Portfolio	Strategy D Nuclear Focused Resource Portfolio	Strategy E EEDR and Renewable Focused Resource Portfolio
EEDR	1,940 MW & 4.725 annual GWh reductions by 2020	2,100 MW & 5,900 annual GWh reductions by 2020	3,600 MW & 11,400 annual GWh reductions by 2020	4,000 MW & 8,900 annual GWh reductions by 2020	5,100 MW & 14,400 annual GWh reductions by 2020
Renewable additions	1,300 MW & 4,600 GWh competitive renewable resources or PPAs by 2020	Same as Strategy A	2,500 MW & 8,600 GWh competitive renewable resources or PPAs by 2020	Same as Strategy C	3,500 MW & 12,000 GWh competitive renewable resources or PPAs by 2020
Idled coal-fired capacity	No fossil fleet reductions	2,400 MW total fleet reductions by 2017	3,200 MW total fleet reductions by 2017	7,000 MW total fleet reductions by 2017	4,700 MW total fleet reductions by 2017
Energy storage	No new additions	Same as Strategy A	Add on pumped-storage unit	Same as Strategy C	Same as Strategy A
Nuclear	No new additions after WBN2	First unit online no earlier than 2018 Units at least 2 years apart	Same as Strategy B	First unit online no earlier than 2018 Units at least 2 years apart	First unit online no earlier than 2022 Units at least 2 years apart Additions limited to 3 units
Coal	No new additions	New coal units are outfitted with CCS First unit online no earlier than 2025	Same as Strategy B	Same as Strategy B	No new additions
Gas-fired supply (self-build)	No new additions	Meet remaining supply needs with gas-fired units	Same as Strategy B	Same as Strategy B	Same as Strategy B
Market purchases	No limit on market purchases beyond current contracts and extensions	Purchases beyond current contracts and contract extensions limited to 900 MW	Same as Strategy B	Same as Strategy B	Same as Strategy B
Transmission	Potentially higher level of transmission investment to support market purchases Transmission expansion (if needed) may have impact on resource timing and availability	Complete upgrades to support new supply resources	Increase transmission investment to support new supply resources and ensure system reliability Pursue inter-regional projects to transmit renewable energy	Same as Strategy C	Potentially higher level of transmission investment to support renewable purchases Transmission expansion (if needed) may have impact on resource timing and availability

Defined model inputs ☐ Optimized model inputs

Figure 6-6 – Strategy Descriptions

Strategy components were utilized in the modeling in several different ways. For example, Strategy A has specific defined constraints, such as including no new coal additions and 1,300 MW of renewable resource additions. Other components specified timing, such as adding nuclear resources no earlier than 2018 and no new coal additions in Strategy B. Reactive constraints were also identified, such as the need to build additional transmission capacity if imports from renewables exceed a certain limit.

6.2 Resource Portfolios Optimization Modeling

The generation of resource portfolios was a two-step process. First, an optimized capacity expansion plan was generated, which was then followed by a financial analysis. This process was repeated for each strategy/ scenario combination and for additional sensitivity runs.

6.2.1 Development of Optimized Capacity Expansion Plan

TVA utilized a capacity optimization model, System Optimizer, which is an industry standard software model developed by Ventyx. This model utilized an optimization technique where an "objective function" (i.e., total resource plan cost) was minimized and subject to a number of constraints by using mixed integer linear programming.

Resources were selected by adding or subtracting assets based on minimizing the present value of revenue requirements (PVRR). PVRR represents the cumulative present value of total revenue requirements for the study period based on an eight percent discount rate. In other words, it is the today's value of all future costs for the study period discounted to reflect the time value of money and other factors, such as investment risk.

In addition, the following constraints were observed:

- Balance of supply and demand
- Energy balance
- Reserve margin
- Generation and transmission operating limits
- Fuel purchase and utilization limits
- Environmental stewardship

System Optimizer uses a simplified dispatch algorithm to compute production costs. The model used a "representative hours" approach in which average generation and load values in each representative period within a week were scaled up appropriately to span all hours of the week and days of the months.

Year-to-year changes in the resource mix were then evaluated and infeasible states were eliminated. The least-cost path (based on lowest PVRR) from all possible states in the study period was retained in the Draft IRP as the optimized capacity expansion plan.

6.2.2 Evaluation of Detailed Financial Analysis

Next, each capacity expansion plan was evaluated using an hourly production costing algorithm, which calculated detailed production costs of each plan, including fuel and other variable operating costs. These detailed cost simulations provided total strategy costs and financial metrics that were used for evaluation of the results.

This analysis was accomplished using another Ventyx product called Strategic Planning (MIDAS). This software tool uses a chronological production costing algorithm with financial planning data used to assess plan cost, system rate impacts and financial risk. It also utilized a variant of Monte Carlo analysis[1], which is a sophisticated analytical technique that varies important drivers in multiple runs, to create a distribution of total costs rather than a single point estimate, which allows for risk analysis. The Monte Carlo analysis in MIDAS utilized 13 key variables.

The following variables were selected by TVA for the analysis:

- Commodity prices – natural gas, coal, CO_2, SO_2 and NO_x allowances
- Financial parameters – interest rates and electricity market prices
- Operating costs – capital as well as operation and maintenance
- Dispatch costs – hydro generation, fossil and nuclear availability
- Load forecast uncertainty

Total PVRR for each resource plan was calculated taking into account additional considerations. These considerations included the cash flows associated with financing. The model generated multiple combinations of the key assumptions for each year of the study period and computed the costs of each combination. Capital costs for supply-side options were amortized for investment recovery using a real economic carrying cost method that accounted for unequal useful lives of generating assets.

[1]Monte Carlo analysis is also referred to as stochastic analysis

Present value calculations are widely used in business and economics to provide a means to compare cash flows at different times on a meaningful basis. It also ensures that assets with higher capital costs and longer service lives are not unduly penalized relative to assets with lower capital costs and relatively shorter economic lives.

The short-term rate metric was also calculated and provided an alternative representation of the revenue requirements for the 2011-2018 timeframe expressed per MWh. This metric was developed to focus on the near-term impacts to system cost in recognition of TVA's current debt cap of $30 billion and the likelihood that the majority of capital expenditures in the short–term[1] may have to be funded primarily from rates.

6.2.3 Development of Portfolio

Portfolios are the output of the modeling process described in Section 6.2 – Resource Portfolios Optimization Modeling, and represent the outcome of choices made for a given view of the future. During the Draft IRP process, an optimized portfolio was developed for each of the five planning strategies within each of the six scenarios and for the Reference Case: Spring 2010. The end result was 35 distinct portfolios. Each portfolio represented a 20-year capacity expansion plan. The portfolios consisted of assets that represented various resource selections and cost characteristics optimized to meet TVA's capacity and energy needs for the IRP study period.

Due to the nature of the analysis, certain elements (i.e., emphasis on EEDR and nuclear energy) of some strategies remained relatively constant across the scenarios. However, other elements (i.e., amount of natural gas-fired capacity and market purchases) were variable and determined by the interplay between each planning strategy and the scenario within which it was analyzed.

6.3 Development of Evaluation Scorecard

The use of a scenario planning approach, combined with multiple strategies to be considered, resulted in a large number of distinct 20-year resource portfolios that required analysis and evaluation. Rather than looking for the best single solution contained within a large number of portfolios, the scenario planning approach looked for trends or characteristics common to multiple portfolios with a focus on outcomes considered to be successful and the strategies that guided those outcomes. Definition of what is considered successful, although difficult, was a key component in the evaluation of the planning strategies. Development of a scorecard to communicate the success or failure of the different portfolios was vital to the success of this evaluation process.

[1]prior to 2018

The following sections describe the creation of the IRP scorecard, including development of the ranking and strategic metrics. Although not part of the scorecard, the development of a technology innovation narrative is also discussed below.

6.3.1 Scorecard Design

Identification of preferred planning strategies in the Draft IRP and development of the Recommended Planning Direction in the final IRP involved a trade-off analysis. The analysis was focused on multiple metrics of cost, risk, environmental impacts and other aspects of TVA's overall mission.

A scorecard was designed for each strategy and was used to facilitate this trade-off analysis. The scorecard template (Figure 6-7) was comprised of two sections – ranking metrics and strategic metrics. A technology innovation narrative was included apart from the scorecard to help identify which strategies would be supported by particular technology innovations.

	Ranking Metrics			Strategic Metrics				
	Financial Impact			Environmental Stewardship			Economic Impact	
Portfolio	Cost	Risk	Ranking Metric Score	Carbon Footprint	Water Impact	Waste Impact	Total Employment	Growth in Personal Income
		Total Score:						

Figure 6-7 – Planning Strategy Scorecard

Ranking Metrics

Ranking metrics were used to quantify the financial impact of each given portfolio. Two metrics, cost and risk, were selected based on their ability to highlight differences between the portfolios. To further highlight differences, the ranking metric score was calculated as a blend of the two metric's scores.

Cost Metric

Production of the financial metrics PVRR and short-term rates was described in Section 6.2.1. The cost metric used in the strategy scorecard combined these two metrics using the following weighted formula:

Cost = 0.65 * PVRR + 0.35 * short-term rates

By considering the expected values for PVRR and short-term rates, TVA was able to better evaluate the cost and rate implications for various portfolios. The inclusion of both short-term rates and total revenue requirements helped to facilitate a trade-off analysis of alternative resource plans. This allowed TVA to explicitly evaluate funding implications, consistent with stakeholder concerns regarding increasing rate pressures.

Risk Metric

The PVRR risk metric was computed using both a risk ratio and a risk/benefit ratio metric for each portfolio, as shown in Figure 6-8.

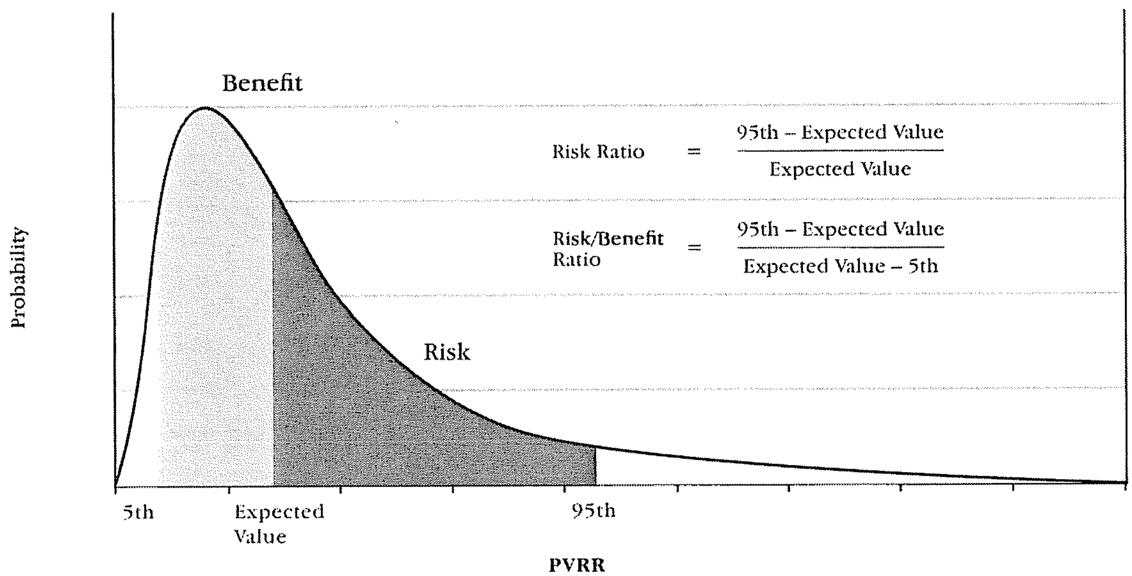


Figure 6-8 – Financial Risk Metrics

The risk metric used in the strategy scorecard combined these two metrics using the following weighted formula.

Risk = 0.65 * risk ratio + 0.35 * risk/benefit ratio

The risk ratio was expressed as the ratio of the difference between the 95th percentile of PVRR from the stochastic analysis and the expected value. It is a measure of the absolute "size" of the risk relative to the expected cost under each strategy within each scenario. A higher value signifies a portfolio with a relatively higher level of risk. The risk/benefit ratio captured the "risk" of a portfolio by examining the potential of exceeding the expected PVRR compared to the benefit of not exceeding the expected PVRR, expressed as a ratio. It compared the potential risks and the potential benefits of a strategy to determine whether or not the "risks and rewards" balance was weighted in favor of the customer.

Ranking Metric Score

The ranking metrics score combined the cost and risk metrics using the following weighted formula.

Ranking metrics score = 0.65 * cost + 0.35 * risk

This metric allowed evaluation of the interaction between financial risks and overall plan cost. For example, desirable low costs may require accepting a greater risk exposure, or to achieve an acceptable level of financial risk may mean selecting a plan with costs that are slightly higher than the least-cost option. The trade-offs required to balance these competing objectives helped identify the preferred planning strategies in the Draft IRP and the Recommended Planning Direction in the final IRP.

Strategic Metrics

Strategic metrics developed to consider other parts of TVA's mission were paired with ranking metrics to complete the IRP scorecard. Two strategic metrics were developed – environmental stewardship and economic impact.

Environmental Stewardship Metric

The environmental stewardship metric was developed to evaluate air, water and waste impacts. In the air metric evaluation, CO_2, SO_2, NO_x and Hg emissions were calculated for each portfolio. Emissions trends for SO_2, NO_x and Hg were steeply reduced because all cases chose large levels of coal-fired unit idling (2,000-7,000 MW) and controlled (90 percent or better emission removal rates) operating units in the future. For simplicity, the air metric was represented as a CO_2 impact footprint factor (annual average tons) because similar trend lines were tracked in all cases for CO_2. No additional significant insight was gained using all air emissions as opposed to using only CO_2. Therefore, the air metric is represented as a CO_2 impact "footprint" factor (annual average tons).

The water component of the environmental stewardship metric represents the thermal load produced through the condenser cooling cycle from steam generating plants to measure thermal impacts to the environment. The water impact was estimated based on the total heat dissipated by the condenser in the generation cooling cycle.

In addition to air and water impacts, certain generation sources produce waste streams that require disposal. The waste component used in this analysis focused on coal and nuclear generation, which are the primary sources of waste streams. The volumetric and disposal costs were used to better normalize differences in mass generated (tons). Waste streams that were estimated included coal ash, flue gas desulfurization/scrubber waste and high- and low-level nuclear waste.

The final evaluation criteria for both water and waste relied on surrogate measures as a proxy for environmental impacts. Both provided a reasonable and balanced method for evaluating planning strategies when compared with other components. Additional detail on the environmental stewardship metrics is in Appendix A – Method for Computing Environmental Impact Metrics.

Economic Impact Metric

Economic impact metrics were included to provide an indication of the impact of each strategy on the general economic conditions in the Tennessee Valley region. The economic metrics were represented by total employment and personal income. These metrics were compared to the impacts of Strategy B – Baseline Plan Resource Portfolio, in Scenario 7.

The IRP study defined economic impact as growth in regional economic activity. Measurement criteria included total personal income in "constant" dollars (i.e., with inflation accounted for) and total employment. These provided measures for the effects of the various planning strategies on the overall, long-term health and welfare of the economy over the next 20 years. This analysis concentrated on changes to the welfare of the general economy due to the strategies. It did not address changes to the distribution of income or employment.

In general, the greater the direct regional expenditures associated with a particular portfolio, the more positive were the effects on the regional economy. This can be offset by the fact that higher rates caused by higher costs have a negative effect on the regional economy. Thus, a resource portfolio that has high expenditures in the Tennessee Valley region may also have high costs and high rates.

The economic impact metrics for a particular planning strategy could be positive or negative depending on the net sum of the expenditure effects and the cost effects. More details about the methodology used to determine the economic impact metrics for the planning strategies is in Appendix B – Method for Computing Economic Metrics.

Scorecard Calculation and Color Coding

The ranking metrics in the scorecard for this IRP were expressed in terms of a 100-point score while ensuring that the relative relationship between the actual values for each portfolio in the strategy was maintained. The following process was used to compute the scores:

- Actual values of ranking metrics (i.e., PVRR, short-term rate impacts) were converted to a relative score on a 100-point scale. This type of scoring helped to assess and prioritize risk and identify the best possible solution
- The highest ranked ("best") value received a 100
- The rest of the scores were based on their relative position to the "best" value (e.g., a value that is 75 percent of the "best" would receive a 75)
- A color-coding method was used to assist in visual comparison of portfolio results. The coding was done within a given scenario. The "best" value for each metric was coded green, the "worst" value was coded red and the values in between were shown with a shaded color that corresponded to the relationship of the score values

An example of the translation from actual values to ranking metric scores is shown in Figure 6-9. The figure shows the conversion for the short-term rate metric.

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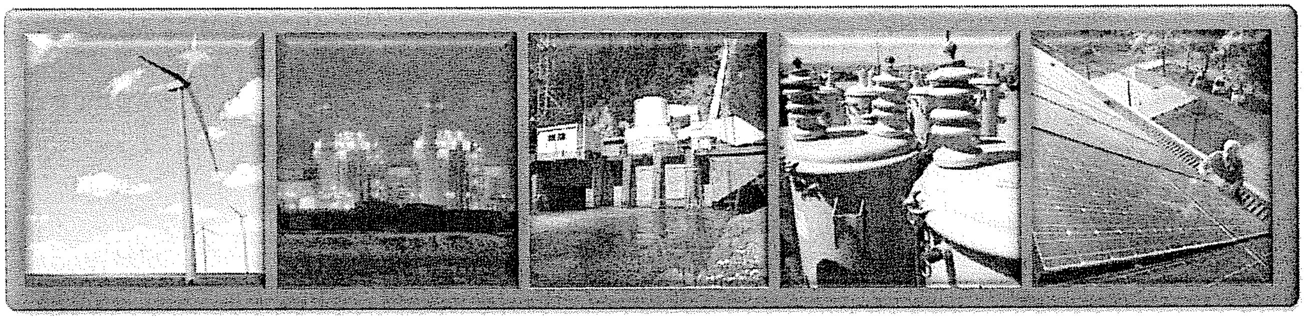

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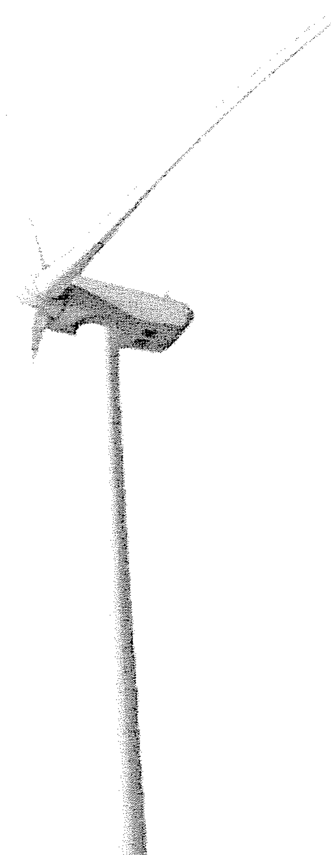

March 31, 2011

This 2011 Integrated Resource Plan (IRP) Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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Solar: *Salt Palace Convention Center Photovoltaic Solar Project*
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Carbon Dioxide Regulatory Compliance Scenarios

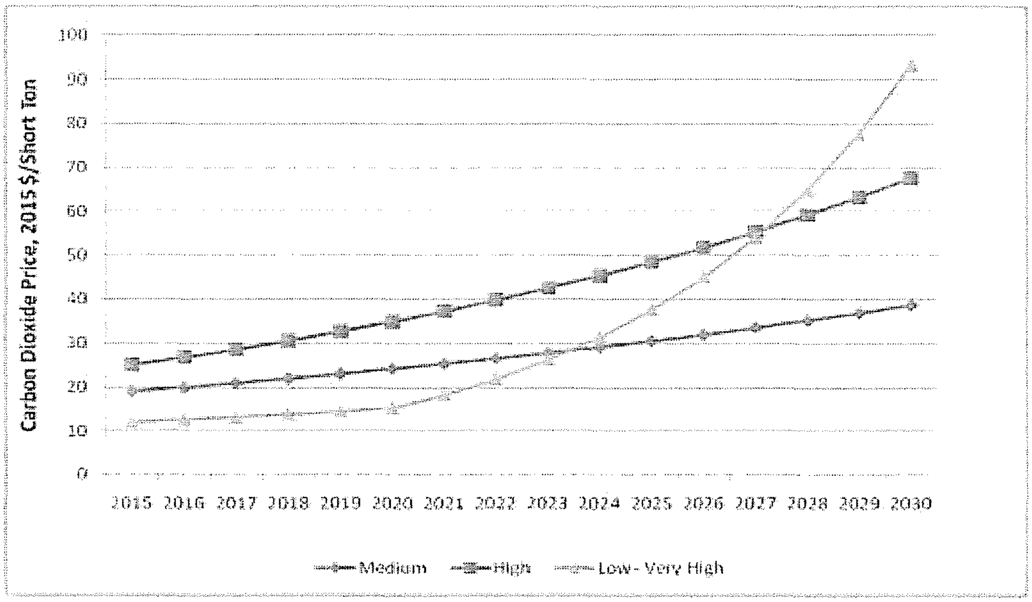
Carbon Dioxide Tax Scenarios

Table 7.2 shows the four CO_2 tax scenarios developed for the IRP. The Medium and High scenarios reflect CO_2 price trajectories contained in recent federal greenhouse gas emission policy proposals, and assume a 2015 start date. The Medium scenario assumes a starting cost of $19 per short ton (2015 dollars) beginning in 2015, with 3 percent annual real escalation plus annual inflation. The High scenario assumes a starting cost of $25 per short ton (2015 dollars) beginning in 2015, with 5 percent annual real escalation plus annual inflation. The Low to Very High scenario assumes a starting cost of $12 per short ton (2015 dollars) beginning in 2015, with 3 percent annual real escalation plus annual inflation through 2020; beginning in 2021, the cost escalates at an 18% annual escalation rate plus inflation. Figure 7.3 is a comparison of the three CO_2 tax trajectories.

Table 7.2 – CO_2 Tax Scenarios

	CO_2 Price, 2015$/short ton			
Year	**None**	**Medium**	**High**	**Low to Very High**
2015	0.00	19.00	25.00	12.00
2016	0.00	19.93	26.73	12.59
2017	0.00	20.93	28.60	13.22
2018	0.00	21.97	30.60	13.88
2019	0.00	23.05	32.71	14.56
2020	0.00	24.18	34.97	15.27
2021	0.00	25.34	37.34	18.30
2022	0.00	26.53	39.85	21.90
2023	0.00	27.81	42.55	26.24
2024	0.00	29.14	45.45	31.43
2025	0.00	30.54	48.54	37.65
2026	0.00	32.00	51.84	45.11
2027	0.00	33.57	55.42	54.09
2028	0.00	35.22	59.24	64.85
2029	0.00	36.94	63.33	77.75
2030	0.00	38.75	67.70	93.23

Figure 7.3 – Carbon Dioxide Price Scenario Comparison



Emission Hard Cap Scenarios

PacifiCorp also modeled two CO_2 system emission hard caps scenarios as alternate compliance mechanisms.[53] Two emission cap scenarios were developed:

- Base: 15 percent below 2005 levels by 2020, and 80% by 2050
- Oregon: 10 percent below 1990 levels by 2020—the Oregon target in H.B. 3543—and 80 percent below by 2050

The hard caps go into effect in 2015. Table 7.3 shows the hard cap emission limits for each scenario.

Table 7.3 – Hard Cap Emission Limits (Short Tons)

Year	Base Emission Limits (15% below 2005 Levels by 2020; 80% by 2050)	Oregon H.B. 3543 Emission Limits (10% below 1990 Levels by 2020; 80% by 2050)
1990		49,878
2005	60,938	
2015	56,968	51,075
2016	55,934	49,838
2017	54,900	48,601
2018	53,866	47,364
2019	52,832	46,127

[53] The Public Utility Commission of Oregon's 2008 IRP acknowledgment order (Order No. 10-066 under Docket No. LC 47) included a requirement to provide analysis of potential hard cap regulations.

Year	Base Emission Limits (15% below 2005 Levels by 2020; 80% by 2050)	Oregon H.B. 3543 Emission Limits (10% below 1990 Levels by 2020; 80% by 2050)
2020	51,798	44,890
2021	50,477	43,726
2022	49,157	42,562
2023	47,837	41,398
2024	46,516	40,235
2025	45,196	39,071
2026	43,876	37,907
2027	42,555	36,743
2028	41,235	35,579
2029	39,915	34,416
2030	38,594	33,252
2050	12,188	9,976

For representing CO_2 emissions associated with firm market purchases and system balancing spot market transactions, PacifiCorp's reporting protocols for calculating its greenhouse gas inventory requires using the EPA's e-Grid sub-region output emission factors for unspecified market transactions. Consequently, the CO_2 emission rate of 902 lbs/MWh is applied for the Mid-Columbia, COB, Mona, and Mead markets, and 1,300 lbs/MWh is applied for the Palo Verde and Four Corners markets.

When modeling a hard cap in System Optimizer, the model generates shadow emission prices in order to meet the hard cap. For example, if the hard cap is not met then the shadow price is increased to decrease the output of the emission-producing stations. These shadow prices are imported into the PaR model to simulate emission-constrained dispatch. Table 7.4 shows the shadow prices generated for the four hard cap cases. The medium CO_2 tax is also used for hard cap cases to reflect assumed regional or federal emission prices that impact wholesale electricity and gas commodity prices used for portfolio modeling. Note that for PaR portfolio cost reporting, PacifiCorp applied the CO_2 tax values to emission quantities rather than the System Optimizer shadow costs to maintain cost comparability among the portfolios.

Table 7.4 – CO_2 Emission Shadow Costs Generated by System Optimizer for Emission Hard Cap Scenarios

Case	15	16	17	18
Hard Cap	Base	Base	Base	Oregon H.B. 3543
Gas Price	Low	Medium	High	Medium
Year	Shadow CO_2 Emission Price ($/ton)			
2015	0	0	0	37
2016	10	8	1	39
2017	11	24	16	35
2018	14	30	34	37
2019	15	34	39	40
2020	17	36	50	43
2021	21	40	64	47
2022	24	43	71	55
2023	28	50	78	70

Case	15	16	17	18
Hard Cap	**Base**	**Base**	**Base**	**Oregon H.B. 3543**
Gas Price	**Low**	**Medium**	**High**	**Medium**
Year	**Shadow CO_2 Emission Price ($/ton)**			
2024	34	57	85	75
2025	38	60	91	75
2026	47	64	94	77
2027	47	62	95	73
2028	51	71	108	83
2029	63	75	114	101
2030	47	61	78	78

Oregon Environmental Cost Guideline Compliance

The Public Utility Commission of Oregon, in their IRP guidelines, directs utilities to construct a base-case scenario that reflects what it considers to be the most likely regulatory compliance future for CO_2, as well as alternative scenarios "ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities." Modeling portfolios with no CO_2 cost represents the current regulatory level. The Medium scenario was considered the most likely regulatory compliance scenario at the time that IRP CO_2 scenarios were being prepared and vetted by public stakeholders (early fall of 2010). Given the late-2010 collapse of comprehensive federal energy legislation and loss of momentum for implementing federal carbon pricing schemes, there is no "likely" regulatory compliance future at the present time (notwithstanding the U.S. EPA's GHG initiative to revise New Source Performance Standards for electric generating units.) PacifiCorp believes that its CO_2 tax and hard cap scenarios reflect a reasonable range of compliance futures for meeting the Public Utility Commission of Oregon scenario development guideline given continued uncertainty. In particular, it should be noted that the hard cap shadow prices for Case 15 exhibit a more moderate trajectory than the Medium scenario, effectively providing a "low" CO_2 tax case for portfolio evaluation.

Case Definition

The first phase of the IRP modeling process was to define the cases (input scenarios) that the System Optimizer model uses to derive optimal resource expansion plans. The cases consist of variations in inputs representing the predominant sources of portfolio cost variability and uncertainty. PacifiCorp generally specified low, medium, and high values to ensure that a reasonably wide range in potential outcomes is captured. For the 2011 IRP, PacifiCorp developed a total of 49 cases.

PacifiCorp defined three types of cases: Energy Gateway scenario evaluation cases, core cases, and sensitivity cases. Energy Gateway scenario evaluation cases were designed to help PacifiCorp's transmission planning department evaluate four Energy Gateway expansion options based on System Optimizer portfolio modeling results. These 16 cases supplement other Energy Gateway economic analysis conducted with the IRP models, profiled in Appendix C.

Core cases focus on broad comparability of portfolio performance results for four key variables. These variables include (1) the level of a per-ton CO_2 tax, (2) the type of CO_2 regulation—tax or hard emission cap, (3) natural gas and wholesale electricity prices based on PacifiCorp's forward price curves and adjusted as necessary to reflect CO_2 tax impacts, and (4) extension date for the federal renewables production tax credit. The Company developed 19 core cases based on a combination of input variable levels. The core case group includes a 2011 business plan "reference" portfolio. This portfolio consists of fixed wind and gas resources for 2011 through 2020, reflecting the major generation projects in the business plan. Also included are four hard cap cases. Because these cases simulate physical emission constraints as opposed to generator emission costs, they do not have emissions profiles comparable to the other portfolios.

In contrast, sensitivity cases focus on changes to resource-specific assumptions and alternative load growth forecasts. The resulting portfolios from the sensitivity cases are typically compared to one of the core case portfolios. PacifiCorp developed 14 sensitivity cases reflecting evaluation of existing coal plant operation, alternative load forecasts, alternative renewable generation cost and acquisition incentives, and demand-side management resource availability assumptions.

In developing these cases, PacifiCorp kept to a target range in terms of the total number (low 50s) in light of the data processing and model run-time requirements involved. To keep the number of cases within this range, PacifiCorp excluded some core cases with improbable combinations of certain input levels, such as a high CO_2 tax and high load growth. (With a high CO_2 tax, a significant amount of demand reduction is expected to occur in the form of energy efficiency improvements, and utility load control programs.)

PacifiCorp also relied heavily on feedback from public stakeholders. The Company assembled an initial set of cases in July 2010, and introduced them to stakeholders at the August 8, 2010, public input meeting. Subsequent updates based on stakeholder comments and Company refinements were reviewed at public input meetings held October 5 and December 15, 2010. One of the key messages from stakeholders was to ensure that the range of cases generate a diverse set of resource types.[54]

Case Specifications

Table 7.5 profiles the portfolio development cases specifications. Reference numbers in the table headings and certain rows correspond to notes providing descriptions of the case variables and explanatory remarks for specific cases that follow the table.

[54] PacifiCorp's IRP public process IRP Web page includes links to documentation on portfolio case development and how stakeholder comments were addressed.

Table 7.5 – Portfolio Case Definitions

Case #	Assumption Alternatives									
	Carbon Policy		Gas Price 2/	Load Growth 3/	Renewable PTC and Wind Integration Cost 4/	Renewable Portfolio Standards 5/	Demand-Side Management	Distributed Solar 10/	Coal Plant Utilization	Energy Gateway Trans 12/
	Type 1/ CO2 Tax Hard Cap	Cost Medium High Low to Very High	Low Medium High	Low Econ. Growth Medium Econ. Growth High Growth High Peak Demand	Extension to 2015 Extension to 2020 Alt. Wind Integ. Cost	None Current RPS Federal RPS	High Achievable 6/ Class 3 Included 7/ Techical Potential 8/ Distribution Efficiency 9/	Current Incentives UT Buydown Levels	No shutdowns Optimized 11/	Base Scenario 1 Scenario 2 Scenario 3
Energy Gateway Scenario Evaluation Cases										
EG1	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base
EG2	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 1
EG3	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 2
EG4	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 3
EG5	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base
EG6	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 1
EG7	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 2
EG8	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 3
EG9	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base
EG10	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 1
EG11	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 2
EG12	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 3
EG13	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base
EG14	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 1
EG15	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 2
EG16	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 3
EG1-WM	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Base
EG2-WM	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 1
EG3-WM	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 2
EG4-WM	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 3
EG5-WM	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Base
EG6-WM	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 1
EG7-WM	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 2
EG8-WM	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 3
EG9-WM	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Base
EG10-WM	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 1
EG11-WM	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 2
EG12-WM	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 3
EG13-WM	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Base
EG14-WM	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 1
EG15-WM	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 2
EG16-WM	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 3

Case #	Assumption Alternatives									
	Carbon Policy		Gas Price 2/	Load Growth 3/	Renewable PTC and Wind Integration Cost 4/	Renewable Portfolio Standards 5/	Demand-Side Management	Distributed Solar 10/	Coal Plant Utilization	Energy Gateway Trans 12/
	Type 1/ CO2 Tax Hard Cap	Cost Medium High Low to Very High	Low Medium High	Low Econ. Growth Medium Econ. Growth High Growth High Peak Demand	Extension to 2015 Extension to 2020 Alt. Wind Integ. Cost	None Current RPS Federal RPS	High Achievable 6/ Class 3 Included 7/ Technical Potential 8/ Distribution Efficiency 9/	Current Incentives UT Buydown Levels	No shutdowns Optimized 11/	Base Scenario 1 Scenario 2 Scenario 3
Core Cases										
1	None	None	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
2	None	None	Medium	Med. Econ. Growth	Extension to 2015	None	High Achievable	Current Incentives	None	Base or Scenario
3	CO2 Tax	Medium	Low	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
4	CO2 Tax	High	Low	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
5	CO2 Tax	Low to Very High	Low	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
6	CO2 Tax	Low to Very High	Low	Med. Econ. Growth	Extension to 2020	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
7	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
8	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
9	CO2 Tax	Low to Very High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
9a	Same assumptions as 9, except using two System Optimizer runs; the first, a 12-year run, determines fixed resources for a subsequent 20-year run 13/									
10	CO2 Tax	Low to Very High	Medium	Med. Econ. Growth	Extension to 2020	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
11	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
12	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
13	CO2 Tax	Low to Very High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
14	CO2 Tax	Low to Very High	High	Med. Econ. Growth	Extension to 2020	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
15	Hard Cap - Base	Medium	Low	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
16	Hard Cap - Base	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
17	Hard Cap - Base	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
18	Hard Cap - OR	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
19	2011 Business Plan resources fixed through 2020; optimized thereafter using Medium scenario assumptions								None	Scenario 3
Coal Plant Utilization Sensitivity Cases										
20	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	Optimized	Base or Scenario
21	CO2 Tax	Medium	Low	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	Optimized	Base or Scenario
22	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	Optimized	Base or Scenario
23	CO2 Tax	High	Low	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	Optimized	Base or Scenario
24	Hard Cap - Base	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	Optimized	Base or Scenario
Load Forecast Sensitivity Cases										
25	CO2 Tax	Medium	Medium	Low Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
26	CO2 Tax	Medium	Medium	High Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
27	CO2 Tax	Medium	Medium	High Peak Demand	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
Renewable Resource Sensitivity Cases										
28	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	None	High Achievable	Current Incentives	None	Base or Scenario
29	CO2 Tax	Medium	Medium	Med. Econ. Growth	Alt. Wind Integ. Cost	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
30	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	UT $1.50/Watt Incentive	None	Base or Scenario
30a	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	UT $2.00/Watt Incentive	None	Base or Scenario
DSM Sensitivity Cases										
31	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	Class 3 Included	Current Incentives	None	Base or Scenario
32	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	Technical Potential	Current Incentives	None	Base or Scenario
33	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	Distribution Energy	Current Incentives	None	Base or Scenario

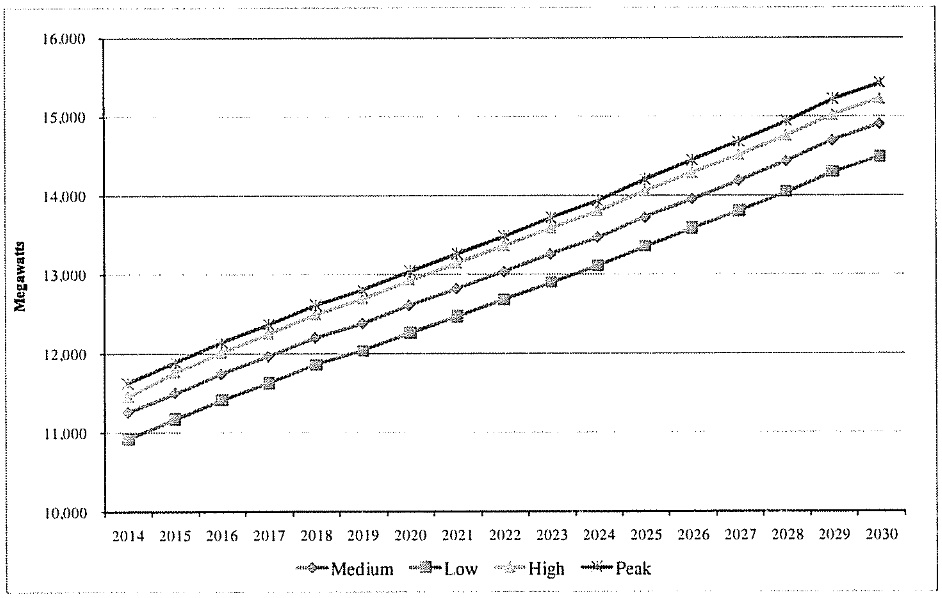
Case Definition Notes

1. The carbon dioxide tax is a variable cost adder for each short ton of CO_2 emitted by PacifiCorp's thermal plants. The CO_2 tax for market purchases is incorporated in the electricity price forecast scenarios as simulated by MIDAS, a regional production simulation model that is described later in this chapter. These marginal wholesale electricity price forecasts, by market hub, are then fed into System Optimizer. The hard cap is a physical CO_2 emissions limit placed on system generation and purchases.

2. The high, medium, and low natural gas price forecasts are based on a review of multiple forecasting service company projections, and incorporate the CO_2 tax assumptions associated with the case definitions. Details on the price forecasts and supporting methodology are provided later in this chapter.

3. The main purpose of the alternative load forecast cases is to determine the resource type and timing impacts resulting from a structural change in the economy. The focus of the load growth scenarios is from 2014 onward. The Company assumes that economic changes begin to significantly impact loads beginning in 2014, the currently planned acquisition date for the next CCCT resource. For the low economic growth scenario (Case 25), another economic recession hits in 2014. For the high economic growth scenario (Case 26), the economy is assumed to fully recover from the current recession by 2014 and significantly expand beginning at that point. Low and high load forecasts are one-percent decreases and increases, respectively, for economic drivers, relative to the Medium forecast. PacifiCorp developed the "high peak demand" forecast by assuming one-in-ten (10 percent probability of exceedence) high temperature loads. Figure 7.4 shows the low, high, and high-peak load forecasts relative to the medium case. Note that the capacities reflect loads before any adjustments for demand-side management programs are applied. See Appendix A for a detailed description of the forecast scenarios.

Figure 7.4 – Load Forecast Scenario Comparison



4. The "PTC extension to 2015" assumption is consistent with PacifiCorp's 2011 business plan. The "PTC extension to 2020" assumption was recommended by a public stakeholder.

   A wind integration cost of $5.38/MWh (versus $9.70/MWh as reported in PacifiCorp's wind integration study dated September 1, 2010) was used for the alternative wind integration cost case as recommended by Renewable Northwest Project based on their independent analysis. The PTC is assumed to expire by 2015 for the alternate wind integration cost case.

5. The current RPS assumption is a system-wide requirement based on meeting existing state RPS targets under the Multi-State Protocol Revised Protocol. States with applicable resource standards include California, Oregon, Washington, and Utah. The table below shows the incremental system renewable energy requirement after accounting for state eligible resources acquired through 2010. Based on RPS compliance analysis using the compliance targets proposed by Senator Jeff Bingaman, along with PacifiCorp's eligible renewable resources through 2010, PacifiCorp would comply with this federal RPS proposal until 2030. The federal RPS scenario assumes the higher Waxman-Markey (H.R. 2454) targets that passed the U.S. House of Representatives in June 2009. This RPS scenario was used for Energy Gateway and 2011 IRP preferred portfolio scenario analysis. Table 7.6 below compares the Bingaman and Waxman-Markey combined renewables/electricity savings compliance targets and the renewable-only targets estimated by PacifiCorp.

Table 7.6 – Comparison of Renewable Portfolio Standard Target Scenarios

		Bingaman		Waxman-Markey (H.R. 2454)	
Year	Current RPS 1/ (System Basis)	Compliance Target	Renewable Percentage 1/	Compliance Target	Renewable Percentage 2/
2015	0.0%	3.0%	2.3%	9.5%	7.1%
2016	0.0%	3.0%	2.3%	13.0%	9.8%
2017	0.0%	3.0%	2.3%	13.0%	9.8%
2018	0.0%	6.0%	4.5%	16.5%	12.4%
2019	0.0%	6.0%	4.5%	16.5%	12.4%
2020	0.1%	6.0%	4.5%	20.0%	15.0%
2021	2.0%	9.0%	6.8%	20.0%	15.0%
2022	2.2%	9.0%	6.8%	20.0%	15.0%
2023	2.2%	12.0%	9.0%	20.0%	15.0%
2024	2.3%	12.0%	9.0%	20.0%	15.0%
2025	3.2%	15.0%	11.3%	20.0%	15.0%
2026	3.2%	15.0%	11.3%	20.0%	15.0%
2027	3.2%	15.0%	11.3%	20.0%	15.0%
2028	3.2%	15.0%	11.3%	20.0%	15.0%
2029	3.1%	15.0%	11.3%	20.0%	15.0%
2030	3.2%	15.0%	11.3%	20.0%	15.0%

1/ Reflects additional renewable energy requirement after accounting for eligible resources acquired through 2010.
2/ Reflects the forecasted renewable portion of a combined renewable/electricity savings requirement.

6. A high achievable percentage assumption of 85 percent for DSM programs applies to all portfolios. The Cadmus Group's base achievable assumption for the 2007 DSM potential study, prior to Company adjustment, was 55 percent.

7. For sensitivity Case 31, System Optimizer is allowed to select price-responsive DSM programs. These programs, outlined in Chapter 6, include residential time-of-use, commercial/industrial real-time pricing, commercial/industrial demand buyback, commercial/industrial load curtailment, commercial critical peak pricing, and *mandatory* irrigation time-of-use rates.

8. This assumption is intended to meet the Public Service Commission of Utah's DSM evaluation requirements. DSM is modeled based on technical potential.

9. PacifiCorp modeled a Washington-only conservation voltage reduction (CVR) resource based on estimated energy savings and costs for 19 distribution feeders analyzed as part of a consultant study.[55] The sensitivity analysis serves as a proof-of-concept test for future resource modeling. The levelized cost and resource capacity by Washington topology bubble is shown in the following table:

Location	Levelized Average Cost 1/ (2010 $/MWh)	Capacity (MW)
Walla Walla	63	0.191
Yakima	66	0.403

1/ Costs exclude credits applied to meet Initiative 937 methodology requirements documented in Chapter 6.

10. This case is intended to meet the Public Service Commission of Utah's distributed solar evaluation requirements. For Case 30, Utah roof-top PV resources were modeled with a program incentive cost (capital cost) of $1,744/kW, which includes a 14 percent administrative and marketing cost gross-up. For Case 30a, the resources were modeled with a program cost of 2,326/kW, including the 14 percent administrative and marketing cost gross-up. Resource potential in Utah is 1.2 MW per year, reaching 24 MW by 2030.[56]

11. The five coal plant utilization sensitivity cases are designed to investigate, as a modeling proof-of-concept, the impacts of CO_2 cost and gas price scenarios on the existing coal fleet after accounting for: incremental environmental compliance, fueling, decommissioning, and coal contract liquidated damages, as well as recovery of remaining plant depreciation. System Optimizer is allowed to select the optimal coal plant shut down dates. This study is limited to CCCT replacement resources with an earliest in-service date of 2016. The simulation period covers 2011 through 2030. More details on specification of the coal plant utilization model set-up are provided later in this chapter.

[55] The study was conducted by a consulting team led by Commonwealth Associates, Inc. The modeled resource reflects preliminary findings of the study. The consulting team applied the Distribution Efficiency Initiative (DEI) average Pacific Northwest conservation load shape to the 19 distribution feeder efficiency measures to derive hourly energy savings for use by System Optimizer. DEI was a three-year study initiated in 2005 by the Northwest Energy Efficiency Alliance to investigate the cost-effectiveness of distribution efficiency and voltage optimization measures.

[56] Resources are modeled by topology bubble. The Utah solar PV resource was located in the Utah North bubble, which includes a portion of Idaho and southwestern Wyoming. The total solar PV capacity potential per year for Utah North is 1.3 MW, consisting of 1.2 MW for Utah, 0.18 MW for Wyoming, and 0.07 MW for Idaho.

12. Energy Gateway transmission scenarios are defined by including certain transmission expansion segments. Table 7.7 shows the segments assigned to the Energy Gateway scenarios. Capital costs for each scenario included in System Optimizer are also shown. PacifiCorp ultimately developed 32 portfolios reflecting the base RPS assumption and the higher Waxman-Markey targets (Cases designated with a "-WM" extension). Modeling assumptions, transmission maps, and results are provided in Chapter 4.

    For the Base scenario, both the Populus - Terminal and Mona - Oquirrh projects have a Certificate of Public Convenience and Necessity (CPCN). The Sigurd - Red Butte and Harry Allen projects are not considered transmission resource options because they are reliability/grid reinforcement investments necessary for serving southwestern Utah loads, and not justified based on supply-side resource expansion elsewhere on the system. The "Hemingway - Boardman - Cascade Crossing" transmission project is treated as a resource option in Scenario 3 due to the dependency on the Populus - Hemingway segment.

Table 7.7 – Energy Gateway Transmission Scenarios

Energy Gateway Segments by Scenarios			
Base	**Scenario 1**	**Scenario 2**	**Scenario 3**
Gateway Central (Populus-Terminal and Mona-Oquirrh)	Gateway Central	Gateway Central	Gateway Central
Sigurd - Red Butte	Sigurd - Red Butte	Sigurd - Red Butte	Sigurd - Red Butte
Harry Allen Upgrade	Harry Allen Upgrade	Harry Allen Upgrade	Harry Allen Upgrade
	Windstar - Populus	**Windstar - Populus**	**Windstar - Populus**
		Aeolus - Mona	**Aeolus - Mona**
			Populus - Hemingway
			Hemingway-Boardman-Cascade Crossing
Total Capital Cost (Million $)			
1,776	3,329	4,609	5,888

13. Two portfolios were developed for Case 9. The portfolio for Case 9 is a conventional 20-year System Optimizer run. Portfolio 9a represents the outcome of two System Optimizer runs; the first run was a 12-year run, while the second run was a 20-year run with the resources fixed for the first ten years based on the 12-year run. (The 12-year run mitigates the optimization period end effects that would be present on a ten year run.) These portfolios are intended to support analysis required in the Public Utility Commission of Oregon's 2008 IRP acknowledgment order (Order No. LC 47). They also support the Oregon Commission's "Trigger Point Analysis" IRP standard (Order No. 08-339).

2. Planning Scenarios

Highlights

- *Ameren Missouri worked with Charles River Associates to define and model ten planning scenarios.*
- *The planning scenarios are defined by a probability tree which is comprised of three uncertain factors: carbon policy, natural gas prices, and load growth.*
- *The three uncertain factors are dependent in that they have interactive effects. They are also considered to be critical, as different values could sway resource selection.*
- *For each of the three critical dependent uncertain factors, subjective probability distributions were identified by subject matter experts using formal decision analysis techniques.*

Ameren Missouri consulted Charles River Associates (CRA) to help determine the critical factors that should define the planning scenarios, elicit subjective probabilities from Ameren Missouri experts about those variables, and then model those scenarios with their integrated environmental and economic model. Based on prior modeling experience, three interactive variables were chosen to define scenarios and are expected to have the largest impact on future resource choices: carbon policy, natural gas prices, and load growth. Based on the outcomes of the expert interviews, Ameren Missouri adopted 10 scenarios to represent the uncertainty of the three critical variables. CRA modeled each scenario to provide the necessary internally-consistent inputs for further IRP analysis. The load forecasts for Ameren Missouri, as seen in Chapter 3, were developed to be consistent with the same uncertainty expected by internal experts and on which the planning scenarios were based. Chapter 9, Modeling and Risk Analysis, discusses the details of how the scenarios were used to judge the performance of alternative resource plans as well as the results of further sensitivity analysis of additional uncertain factors.

2.1 Scenarios and the Probability Tree

The building and analysis of several "scenarios" of key future market outcomes for national-scale variables is the starting point for the evaluation of resource plans, and the first step of the risk analysis. These scenarios make up a "probability tree," meaning that each scenario has a probability associated with it, and that the scenarios as a group were developed to span a full probable range of relevant market outcomes. The probability tree is developed to describe multiple combinations of critical uncertain factors that have interrelated (or "dependent") impacts on projections of multiple energy and environmental variables. The "critical" variables comprising the probability tree are those for which reasonably likely alternative forecasts could significantly sway the evaluation of candidate resource plans.

For each scenario in the probability tree, Ameren Missouri must have "integrated" sets of forecasts of the "nationally-defined" inputs to IRP calculations of resource plan revenue requirements. In this context, the term "integrated" denotes that all of the individual variable projections for a particular scenario are mutually consistent with one another, which requires a model with the ability to simultaneously simulate interactions in fuel and energy markets, electricity generation system operation, non-electricity sector outcomes, macroeconomic activity levels, and sector-specific responses to emissions limits.

The term "nationally-defined" denotes that the projected outcome is determined by supply and demand events that occur on a scale larger than that of Ameren Missouri or its territory, and would apply to such variables as U.S. electricity demand. Charles River Associates' (CRA's) MRN-NEEM model, a computable general equilibrium representation of the full U.S. economy integrated with a dispatch model of individual electricity generating units, satisfies both of the above criteria. By simulating each scenario as an MRN-NEEM model run, Ameren Missouri can produce integrated, nationally-defined projections of the inputs to the detailed, system-level IRP evaluations.

In the Sensitivity Analysis step of the IRP risk analysis, other uncertain variables are evaluated and the critical independent uncertain factors are identified and then added to the scenario probability tree. As the name implies, independent uncertain factors are those whose impacts on multiple energy and environmental projections are not regarded as interrelated. This topic is discussed in detail in Chapter 9.

2.2 Critical Dependent Uncertain Factors

To determine which variables should comprise the probability tree and to determine the associated probabilities, Ameren Missouri consulted the firm Charles River Associates (CRA) to assist. Although Ameren Missouri developed a list of 22 candidate uncertain factors, as seen in Table 2.1,[1] the relevant variables for this step are those which are subject to a range of uncertainty within which different values might significantly sway the evaluation of

Table 2.1 Candidate Uncertain Factors

Load Growth	DSM Cost
Interest Rates	Off-System Sales
Carbon Policy	Investment Tax Credit
Fuel Prices	Variable O&M
Project Cost	Return on Equity
Project Schedule	Hourly Price Shapes
Purchased Power	Power Price Volatility
Emissions Prices	Nuclear Incentives
Fixed O&M	Wind Capacity Factor
Forced Outage Rate	Solar Capacity Factor
DSM Load Impacts	Transmission Interconnection Costs

[1] 4 CSR 240-22.070(2); 4 CSR 240-22.070(11)(A)2.;

resource plans (i.e., can be critical to the resource plan decision), and that are nationally-defined in scope. Identifying individual variables rather than complex packages of multiple variable outcomes facilitates the expert elicitation process described in the next section of this chapter. The various combinations of these critical, nationally-defined variables, and their associated likelihoods, will form the scenarios represented in the final probability tree. Each of these scenarios will be analyzed as an MRN-NEEM model run, which will produce internally-consistent, integrated projections of key IRP inputs to the standard Ameren Missouri system-level analysis of resource plans.

Following a review of the results and assumptions from previous analysis between Ameren Missouri and CRA, including that performed for Ameren Missouri's 2008 IRP, it was determined that the appropriate variables for probability elicitation were: load growth, carbon policy, and natrual gas prices.

Four other variables were also considered to be potential components of the scenario probability tree[2]. It was determined that the IRP decisions would not be as sensitive to these three variables for the reasons explained below:

- Gross Domestic Product (GDP) – It was determined that uncertainty in this variable would affect IRP outcomes primarily in the way it would affect other critical variables, particularly electricity demand growth and natural gas prices, and thus the IRP-relevant aspects of GDP uncertainty could be folded into the latter two uncertainty representations;

- Lower coal prices – Lower coal commodity prices would tend to be offset by carbon prices under a world with a carbon cap, which we expected would play a high-probability role in the IRP tree. Also, because Ameren Missouri is not modeling new uncontrolled coal as a resource option, the range of uncertainty expected in coal prices is unlikely to substantially affect the choice among the non-coal IRP alternatives;

- Construction costs – Although this variable is expected to influence resource selection it was evaluated as an independent uncertainty in the risk analysis. Construction costs do not have strong interrelated effects compared to the other variables being considered;

- 3-P Emission Prices[3] – Modeling results indicate that, unlike for carbon, wide variations in "3-P" (mercury, SO_2, NO_X) emissions prices have very little impact on IRP-relevant inputs and outputs. The determination to exclude variations in 3-

[2] EO-2007-0409 – Stipulation and Agreement #35; 4 CSR 240-22.070(2)

[3] 4 CSR 240-22.040(8)(D)2.

P policy from the scenario tree was based upon sensitivity analysis conducted for Ameren Missouri's 2008 IRP, in which variations in CAIR and CAMR caps produced insignificant changes to critical IRP drivers. At the time when CRA and Ameren Missouri discussed what variables should be included in the scenario tree both CAIR and CAMR had been remanded, and the form of any replacement legislation was very unclear. For mercury, the political backdrop was gravitating strongly towards a MACT approach and away from cap-and-trade, so the decision was to institute a two-phase mercury reduction requirement (the move to MACT also meant that there was no longer going to be an allowance price for Mercury). However, lacking a specific legislative alternative to CAIR, the CAIR SO_2 and NO_X caps were simulated as originally written. After the MRN-NEEM analysis was completed, the EPA proposed the Clean Air Transport Rule (CATR) to replace CAIR, with more stringent caps. Simultaneously, momentum has gathered behind SO_2 and NO_X MACT requirements triggered by new hazardous air pollutant (HAP) rules. CATR would likely produce higher SO_2 and NO_X allowance prices, but any resulting impacts on critical IRP drivers would not be more influential than the impacts caused by carbon policy, natural gas prices, and load growth. In addition, if CATR were to be paired with MACT requirements for both SO_2 and NO_X, then allowance prices for SO_2 and NO_X might be elevated for one or two years, but would then collapse as all units would be required to add controls thereby making the caps non-binding. Later in the risk analysis Ameren Missouri evaluated more stringent environmental regulations to model the effects on existing plants and the resultant impact on resource needs.

2.3 Assigning Subjective Probabilities

The appropriate individual to assign subjective probabilities is the decision-maker or the person(s) that the decision-maker designates as the best expert(s). Ameren Missouri's management identified several in-house experts to provide the probability distributions for each critical dependent uncertain variable. (Later, senior Ameren Missouri management (the decision-maker) reviewed the resulting subjective probabilities and their basis, and approved them for use in the IRP risk analysis).

CRA structured each probability elicitation session following key principles of sound probability encoding techniques. The process had the following structure.

- First, the purpose of the elicitation process – to minimize natural cognitive biases – was explained, as was the planned use in the IRP of information that would be the subject of the interview. Potential areas of motivational bias were also explored before starting each elicitation. (CRA did not detect any concerns in this regard.)

- Next, the variable to be encoded was defined. The interviewer encouraged the expert to describe events and contingencies that would affect his expectations about the outcome of the uncertain variable. If it became apparent that the expert found that the full uncertainty was too complex to analyze as a whole, the interviewer broke it down into a set of simpler constituent parts, following the structure described by the expert. The formal elicitation was then performed on the various contingent variables. (After the completion of the elicitation, CRA reconstructed the overall probability distribution from the contingent elements and their respective probabilities.)
- Third, the interviewer had the expert identify the specific units for each variable to be encoded, conducted a sequence of "conditioning" questions intended to lessen some common sources of cognitive biases, and used a variety of probability elicitation techniques to obtain quantitative statements that, as a group, described the expert's subjective views on the probability distribution for each variable in question.
- At the conclusion of each interview, CRA showed the expert the produced probability distributions and recapped the experts' general thinking that explained the ranges, areas of likelihood, and contingencies. In each case, CRA verified that these were representative of the expert's beliefs before completing the interview.

There were two experts assigned to each variable. Each was interviewed separately. Such multi-expert elicitations invariably result in different views; indeed, the ability to observe these differences of views is one of the benefits of soliciting information separately from more than one expert. After both had been interviewed, CRA summarized the responses of the two into a comparative format, which was then presented in a conference call to the two individuals together.

Where differences were most pronounced, CRA used the statements from the interviews to highlight what seemed to be the differences in information or perspectives explaining the differences. Discussion of these differences was encouraged, following which the experts were given the opportunity to amend their views in light of the additional discussion. CRA also provided a probability distribution that combined their separate views using equal weights, which could be used in the IRP process, once each expert was fully satisfied with his own individual probability distribution. In this way, CRA developed a single probabilistic statement of potential outcomes for each of the three critical variables that Ameren Missouri's in-house experts agreed was a fair representation of their individual sense of the uncertainty, and the range of opinions across the experts within Ameren. The details and results of those elicitations can be found in Chapter 2 – Appendix A.

lbs/MWh). NO_X emission rates, on the other hand, are rather less dependent on the type of coal being used, and are assumed solely determined by generation technology.

NEEM assumes CO_2 emission rates of 205.3 to 215.4 lbs/MMBtu (depending on the type of coal) for coal-based capacity, with CCS technology achieving a 90% reduction in CO_2 emissions. The CO_2 emissions for natural gas-fired combined cycle (CC) and combustion turbine (CT) units are assumed to be 116.7 lbs/MMBtu. NO_X emission rates range from 0.02 lbs/MMBtu (CC) to 0.08 lbs/MMBtu (CT) among emitting new unit types. These rates, in terms of energy input, are then multiplied by the fully loaded heat rate to produce the emission rates of Table 2.8, given in terms of the electricity produced.

To clarify, consider the CO_2 emission rate given below for IGCC with CCS capacity. NEEM assumes that this technology captures and sequesters 90% of the 212.7 pounds of CO_2 emitted per unit of energy input. Thus, the rate of CO_2 released into the atmosphere from a coal with CCS generator is 21.27 lbs/MMBtu. NEEM assumes a heat rate of 9.713 MMBtu/MWh for this capacity type. As a result, the emission rate for coal with CCS units is equal to the product of 21.27 lbs/MMBtu and 9.713 MMBtu/MWh, equal to 207 lbs/MWh.

The cost of mitigating the emissions of a particular pollutant is dependent upon the emissions rate and the market price of an emissions allowance, Ct. In the cap-and-trade scenarios, the market price of CO_2 is represented by a simple CO_2 price. Recall that there is no explicit price on CO_2 emissions in the Federal Energy Bill, Moderate EPA Regulation, and BAU branches of the probability tree.

Similarly, this analysis does not simulate the disbanded CAMR cap-and-trade scheme for mercury emissions, and, in turn, does not produce allowance prices for mercury. For SO_2 and NO_X emissions, however, NEEM estimates allowance prices against all existing environmental regulations in fully-functioning allowance price markets. These are:

- Title IV/Clean Air Interstate Rule (CAIR) for SO_2 – Title IV melds into the CAIR SO_2 program beginning in 2010 when units in the CAIR region (including units in Missouri) are required to submit two allowances for every ton emitted. This increases to 2.86 allowances per ton emitted in 2015 and beyond;
- CAIR Ozone Season NO_X – the CAIR Ozone Season NO_X program began in 2009 for much of the Eastern United States including Missouri, with a second, tighter cap scheduled for 2015 – this cap is applicable for the summer months of May through September;

- CAIR Annual NO_X – the CAIR Annual NO_X program began in 2009 for much of the Eastern United States including Missouri, with a second, tighter cap scheduled for 2015.

NEEM dynamically calculates allowance prices for SO_2 and NO_X emissions subject to each of the above constraints. In general, if an emissions cap is binding at any point during the model horizon, the allowance price is equal to the marginal cost of abating one more pound or ton of pollutant.

NEEM allows for banking, so emissions in a given year do not necessarily match the prescribed annual limits of the program, as given in Table 2.9.

Table 2.9 SO_2, NO_X, and Hg Emissions Limits

	SO_2	NO_X	
	Title IV/CAIR	CAIR Ozone	CAIR Annual
Year	Million Tons	Thousand Tons	Million Tons
2010	8.95	568	1.722
2015	8.95	485	1.268
2018	8.95	485	1.268
2020	8.95	485	1.268
2030	8.95	485	1.268

The degree to which the prescribed caps are binding (i.e., the level of emissions), combined with optimal banking choices, sets the equilibrium allowance price. NEEM determines unit-level emissions for SO_2 and NO_X based on unit-specific fuel choices, existing equipment, retrofit choices, and dispatch, the details of which are described below.

SO_2 emissions in NEEM are dynamically calculated over time in response to a number of endogenous factors. Initial data that is used to calculate SO_2 emissions include the quantity and characteristics of the existing coal fleet, particularly the capacity, existing retrofit equipment, and coal types that can be burned at each unit. NEEM models existing federal SO_2 legislation and rules including Title IV and CAIR. These provide a cap on the level of SO_2 emissions.

The model also includes an estimate of the existing bank of SO_2 allowances entering 2009 (approximately 8.8 million tons) and allows for additional banking or withdrawals from the bank in order to comply with the cap in the most cost-efficient manner possible. The emissions from existing coal units will change over time in response to the SO_2 allowance price projected by NEEM and the SO_2 reduction options available to each unit. Units can reduce their SO_2 emissions in a number of ways.

First, units that do not have a flue gas desulfurization (FGD) retrofit may add one. The cost of these retrofits is a function of the size of the unit and the cost parameters included in Table 2.10.

Table 2.10 Retrofit Costs and Characteristics

All costs are in 2010 dollars.	Reference Size	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Removal Rate
FGD	500	$351	$11.53	$2.18	98%
SCR	243	$234	$0.85	$0.77	90%
SNCR	150	$23.44	$0.35	$1.13	35%
ACI90	250	$2.24	$0.90	$0.61	90%
RPJ90	250	$61.55	$1.12	$0.61	90%
CCS (For Coal)	N/A	$1,706	$1.56	$2.76	90%

A unit will add an FGD if the cost of installing the FGD, as measured in dollars per ton of SO_2 removed, is less than the cost of purchasing allowances for that unit over the useful life of the retrofit.

A second option to reduce SO_2 emissions is to change coal types. As shown in Table 2.6, each coal has different SO_2 contents. If a coal can be delivered to the unit then it can switch to burning that coal.

For units that do not currently burn Powder River Basin (PRB) coal, a capital cost would have to be incurred to account for the boiler modifications necessary to burn PRB coals.

Lastly, a unit can reduce its SO_2 emissions by generating less, particularly if SO_2 emissions costs push it higher up the dispatch curve. All new coal units are assumed to include an FGD and therefore have an SO_2 emission rate that reflects 98% removal of inlet SO_2.

NO_X emissions in NEEM are dynamically calculated over time in response to a number of endogenous factors. Unlike SO_2, NEEM includes initial NO_X emission rates for coal, natural gas, and oil-fired plants. This information is based on NO_X rates reported as part of the EPA's Continuous Emissions Monitoring System (CEMS). As previously described, all emitting units are subject to the caps prescribed by the CAIR NO_X Ozone Season and CAIR NO_X Annual programs.

As with SO_2, there are multiple options for reducing NO_X emissions on existing units. Two retrofits are available to coal units: Selective Catalytic Reduction (SCR) or Selective Non-Catalytic Reduction (SNCR). Units will install these retrofits if the cost per ton of NO_X removed is less than the prevailing NO_X allowance price. The costs and characteristics of SCR and SNCR are included in Table 2.10. The other means through which existing unit can reduce NO_X emissions is by simply generating less. New units, in contrast, are assumed to have controls in place necessary to meet New Source Performance Standards (NSPS). As such, new coal units have a NO_X emission rate of 0.06 lbs/MMBtu, new combined cycle units have a NO_X emission rate of 0.02 lbs/MMBtu, and new combustion turbines have a NO_X emission rate of 0.08 lbs/MMBtu.

Similar to SO_2 emissions, Hg emissions are only from coal-fired units. Hg emissions for any coal unit are a function of the coal burned and the pollution control equipment in place. While there are Hg-specific retrofits, Hg can also be removed as a co-benefit from some non-Hg controls such as FGDs and SCRs.

The Hg co-benefits given in Table 2.11 were provided to CRA by the Electric Power Research Institute (EPRI), and were used as part of comments filed in response to the then-proposed Clear Air Mercury Rule (CAMR).

An earlier table, Table 2.10, lists the two mercury control options available to coal-fired units in NEEM in order to comply with the 60% and 90% mercury reduction requirements in 2015 and 2020.

Table 2.11 Mercury (Hg) Co-Benefits

Equipment in Place			% Removal of Inlet Hg		
PM Control	SO_2 Control	NO_x Control	Bituminous	PRB	Lignite
Fabric Filter	Dry FGD	No SCR	85	25	10
		SCR	90	25	10
	Wet FGD	No SCR	85	75	40
		SCR	90	75	40
	No FGD	No SCR	75	65	10
		SCR	75	65	10
Cold-Side ESP	Dry FGD	No SCR	50	15	10
		SCR	85	15	10
	Wet FGD	No SCR	60	35	35
		SCR	85	35	35
	No FGD	No SCR	35	20	10
		SCR	35	20	10
Hot-Side ESP	Dry FGD	No SCR	0	0	0
		SCR	0	0	0
	Wet FGD	No SCR	55	30	30
		SCR	85	30	30
	No FGD	No SCR	20	0	0
		SCR	20	0	0
Venturi Scrubber	Dry FGD	No SCR	25	15	15
		SCR	60	15	15
	Wet FGD	No SCR	25	15	15
		SCR	60	15	15
	No FGD	No SCR	20	5	5
		SCR	20	5	5

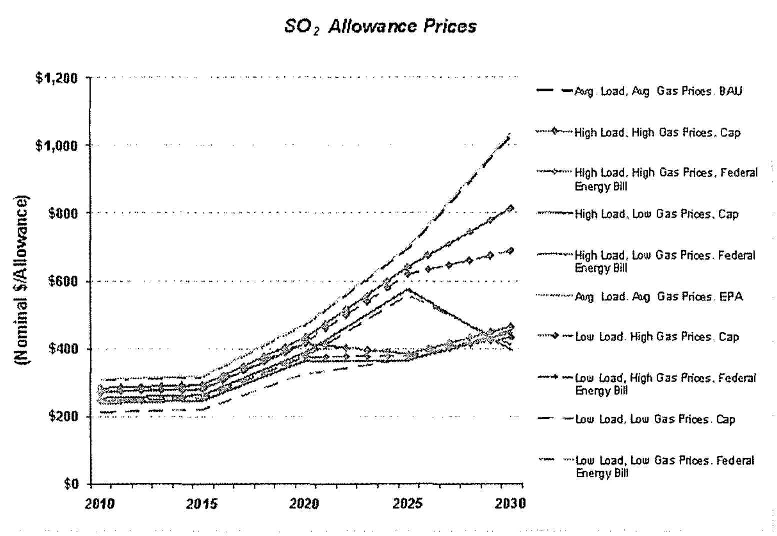
The Activated Carbon Injection (ACI90) technology can only be operated in conjunction with bituminous coal use, and represents a less capital-intensive option for larger units that can rely on existing particulate matter (PM) controls for mercury co-benefits. This ACI90 is only available to units that have already installed a fabric filter. For units without fabric filters, the RPJ90 option is naturally more expensive because it includes the costs of a fabric filter.

With perfect foresight through the end of the modeling horizon, NEEM then optimizes generation patterns, fuel choices and consumption levels, and potential retrofit installations in a manner that minimizes the net present value of total system costs while meeting all reserve margin requirements and complying with all environmental regulations. Allowing for the banking (and subsequent withdrawal) of allowances that could result if permit prices rise faster than the 5% discount rate, NEEM charts an optimal allowance price path through the model horizon.

Again, the resulting allowance price represents the marginal cost of abating one more pound or ton of the pollutant; that is, "Ct," in the equation shown in the column titled "Mitigation Costs" in an earlier table, Table 2.8.

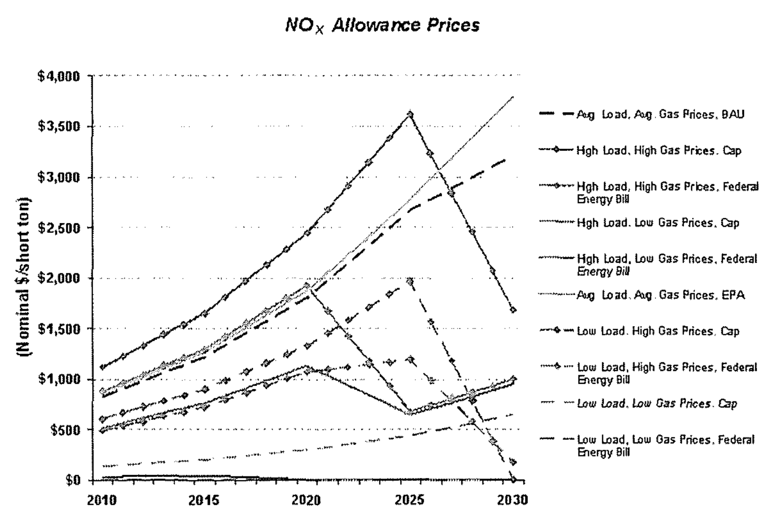
The SO_2 prices for each of the 10 branches in the final probability tree are illustrated in Figure 2.9.

Figure 2.9 SO_2 Allowance Prices



NO_X prices for each of the 10 branches in the final probability tree are illustrated in Figure 2.10. For NO_X allowance prices, Figure 2.10 presents prices under the CAIR NO_X Annual cap.

Figure 2.10 NO_X Allowance Prices



CO_2 permit prices in the cap-and-trade scenarios are shown in Table 2.12.

Table 2.12 CO_2 permit prices

Year	CO2 Price (2010$/metric ton)
2015	$7.50
2020	$17.50
2025	$21.50
2030	$29.25
2035	$37.00
2040	$47.22

Finally, Table 2.13 shows when the SO_2, NO_X, and Hg retrofits are installed on Ameren Missouri coal plants. The year given represents the year when NEEM installs a retrofit on at least half of the unit's capacity.

Table 2.13 SO_2, NO_X, and Mercury Retrofits

Unit	FGD	SCR	ACI90	RPJ90	CCS
Sioux 1	2010			2015	
Sioux 2	2010			2015	
Meramec 1				2015	
Meramec 2				2015	
Meramec 3				2015	
Meramec 4				2015	
Rush Island 1	2020			2015	
Rush Island 2	2020			2015	
Labadie 1	2020			2015	
Labadie 2	2020			2015	
Labadie 3	2020			2015	
Labadie 4	2020			2015	

2.5.8 Electricity Price Forecasts[22]

Forecasts of the market cost of power were derived from MRN-NEEM projections of wholesale electricity prices. The integrated MRN-NEEM modeling framework described in subsections 2.5.1 through 2.5.4 furnishes electricity prices by load block and year for the Eastern Missouri (EMO) region encompassing Ameren Missouri's service territory. This equilibrium electricity price represents the marginal cost of supplying an incremental MWh of electricity in a particular region.

It accounts for (1) the dispatch costs of existing resources and potential new additions, (2) planned maintenance and forced outages at generating units in the region, (3) compliance with all environmental regulations, and (4) a dynamic transmission system that allows for imports and exports between regions. Having sorted all available capacity in a NEEM region by dispatch costs, the model then assesses where the so-constructed supply curve intersects with the demand in a given load block. This determines the wholesale electricity price.

[22] 4 CSR 240-22.050(2)

Supporting Documentation for the Delmarva Delaware IRP Filing Resource Modeling

December 1, 2010

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- In addition to the assumed regulations on air pollutants, units comply with coal combustion byproduct and water withdrawal requirements that are under development by EPA.

Reference Case CO_2 Regulatory Requirements

National CO2 Program

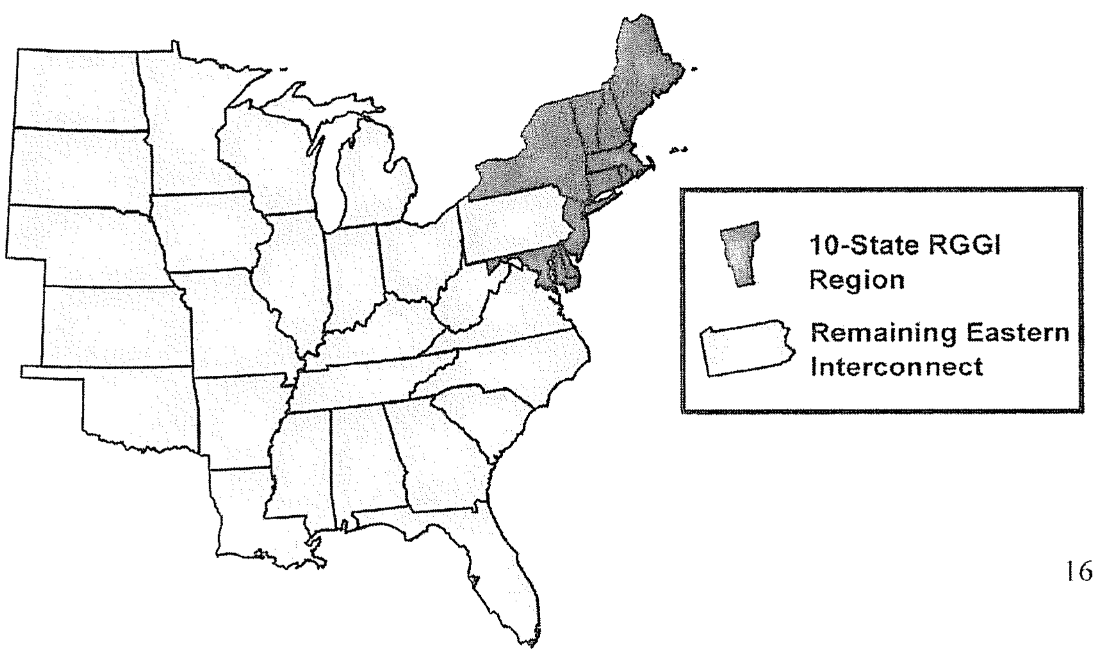
The federal CO_2 legislation considered is modeled afer the 2010 Kerry Lieberman proposal and includes the following details:

- Cap – The cap starts in 2018 at 3% below 2005 levels for affected sources and declines (straight-line) to 83% below 2005 levels in 2050. In 2018, we include the electric and transportation sectors as affected. The cap for those sectors starts at 3% below their 2005 levels in 2018 and gets to 83% below in 2050. We assume the industrials roll into the program in 2023. Its reduction target starts in 2023 at 3% below and straight-lines to 83% below by 2050. We sum those two trajectories together to get to our total cap. The actual compliance obligation is put on the group of affected entities.
- Reserve (backstop) price – The Kerry-Lieberman reserve price is set to start at $25 per metric ton in 2009$ and grow at 5% real per year. Converting that to short tons and 2006$ gets us a reserve price of $21.33/ton in 2018. It then grows at 5% real. In the legislation, the reserve is funded with 4 billion allowances out of the cumulative cap and is intended to control against volatility. This price reflects the marker of what some in Congress might view as a politically viable CO2 price.
- Floor price -- The Kerry-Lieberman auction floor price starts at $12 per metric tonne in 2009$ and grows at 3% real per year.

The Regional Greenhouse Gas Initiative

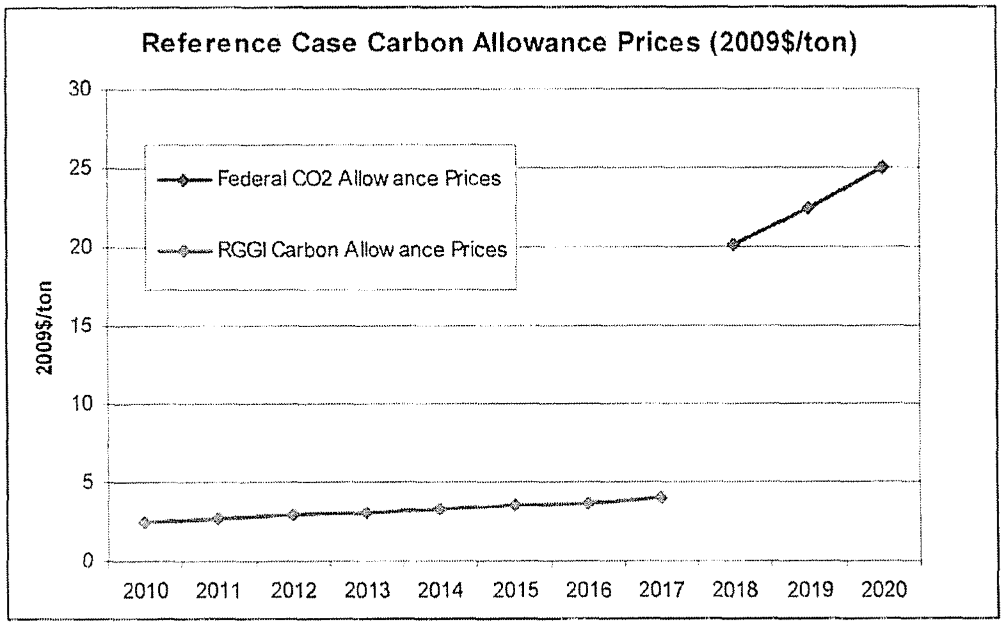
The Regional Greenhouse Gas Initiative (RGGI) is a market-based program to reduce emissions of carbon dioxide (CO_2). Ten states participating in RGGI established a regional cap on CO_2 emissions from the power sector and are requiring power plants to possess a tradable CO_2 allowance for each ton of CO_2 they emit.

Exhibit 3.3: Regional Greenhouse Gas Initiative



The carbon allowance prices for the reference case are shown in Exhibit 3.4.

Exhibit 3.4: Carbon Allowance Pricing Outlook (2009$/ton)



Air Emission Rates and Control Costs

Plant level emissions are determined by the pollutant content of fuels, installed emission control technologies and plant dispatch. Coal power plants have the option to burn multiple types of coal with a range of sulfur and mercury contents. Units may switch fuels to comply with environmental constraints. NOx emission rates for existing units in IPM® were populated based on EPA's 2008 and 2009 Clean Air Markets Emission Database, which is primarily comprised of data from Continuous Emissions Monitoring Systems (CEMS). Mercury emission modification factors are based upon the EPA 1999 ICR data.

Power plants also have the option to install control technologies such as Wet Limestone Forced-Oxidized Scrubber (wet scrubber), Spray Dry Absorbers (dry scrubbers), Activated Carbon Injection (ACI), Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR). Plant retirement and mothballing are also explicitly modeled.

The electricity system also has the capability to reduce emissions by adjusting system dispatch. Under a cap-and-trade system, the model considers the variable cost of emitting (buying allowances) and rearranges system dispatch to minimize generation costs.

Key Environmental Control Cost Assumptions

The capital cost for SCRs shown below does not include the up-front catalyst cost, which is accounted for in variable O&M assumptions. Capital costs for SCRs and SNCRs include adjustments for interest during construction and difficulty factors.

Commonwealth of Kentucky

Before the Public Service Commission

In the Matter of:

THE APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVIENENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMETNAL SURCHARGE	)))))))	Case No. 2011-00161

In the Matter of:

THE APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVIENENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMETNAL SURCHARGE.	)))))))	Case No. 2011-00162

Corrected Direct Testimony of
Jeremy Fisher, Ph.D.

On Behalf of
Sierra Club and Natural Resources Defense Council

PUBLIC VERSION

September 23, 2011

Updated November 2, 2011

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1. INTRODUCTION AND QUALIFICATIONS

Q Please state your name, business address and position.

A My name is Jeremy Fisher. I am a scientist with Synapse Energy Economics (Synapse), which is located at 485 Massachusetts Avenue, Suite 2, Cambridge Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Q Please summarize your work experience and educational background.

A I have ten years of applied experience as a geological scientist, and four years of working within the energy planning sector, including work on integrated resource plans, long-term planning for states and municipalities, electrical system dispatch, emissions modeling, the economics of regulatory compliance, and evaluating social and environmental externalities. I have provided consulting services for various clients, including the U.S. Environmental Protection Agency (EPA), the National Association of Regulatory Utility Commissioners (NARUC), the California Energy Commission (CEC), the California Division of Ratepayer Advocates, the State of Utah Energy Office, the National Association of State Utility Consumer Advocates (NASUCA), National Rural Electric Cooperative Association (NRECA), the State of Alaska, the Western Grid Group, the Union of Concerned Scientists (UCS), Sierra Club, Natural Resources Defense Council (NRDC), Environmental Defense Fund (EDF), Stockholm Environment Institute (SEI), and Civil Society Institute.

Prior to joining Synapse, I held a post doctorate research position at the

University of New Hampshire and Tulane University examining the impacts of Hurricane Katrina.

I hold a B.S. in Geology and a B.S. in Geography from the University of Maryland, and an Sc.M. and Ph.D. in Geological Sciences from Brown University.

My full curriculum vitae is attached as **Exhibit JIF-1.**

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club and the Natural Resources Defense Council.

Q Have you testified previously before the Kentucky Public Service Commission?

A No, I have not.

Q What is the purpose of your testimony?

A My testimony reviews Louisville Gas & Electric and Kentucky Utilities Company's (collectively "the Companies") modeling approach used to determine which units to retire and which to retrofit. I have assessed some of the key variables assumed by the Companies as inputs to their model and, with my colleague Ms. Wilson, have re-run the Companies' planning model and retire/ retrofit spreadsheet model to determine if the analysis would change based on more mainstream assumptions. In this testimony, I will present the results of this re-analysis. My testimony demonstrates that the Companies have chosen a non-economic solution to meet impending environmental requirements for certain coal-fired units and assesses the risk that these units pose to the Companies and their ratepayers.

Q Please identify the Companies' documents and filings on which you base your opinion regarding the Companies' expectations for and treatment of environmental compliance costs affecting its fleet of coal plants.

A In addition to Applications for Certificates of Public Convenience and Necessity (CPCN) and Approval of its 2011 Compliance Plan for Environmental Surcharge with their accompanying witness testimonies and appendices in these cases, I have reviewed the following documents and data prepared by the Companies:

- Integrated Resource Plan (IRP) ("2011 IRP") submitted April 21, 2011
- Selected input and output data from the Strategist Model as used by the Companies in this docket;
- The Companies' retire/retrofit spreadsheet analysis.
- Companies' Discovery responses and rebuttal testimony

Q Is this document the same as your originally filed direct testimony?

A It is not. Significant new information has come to light since the original filing of my original direct testimony, and the Companies have changed at least one underlying set of assumptions, both of which concern forecast natural gas prices. Between the new information from the Companies and the new underlying assumptions, it seemed helpful to both correct my original direct testimony and modify my recommendations in light of the new information, submitting a singular, clean record. I will discuss these changes in more depth later in this testimony.

Q Have you based your findings and opinions on the complete set of filings submitted by the Companies?

A To the best of my knowledge. In my original testimony, I noted that "the Companies filed a very late-breaking supplemental discovery response to Staff's Question 20(b), dated September 14, 2011 ("2011 Air Compliance Plan Supplemental Analysis"). This supplemental response included an entirely new and substantively different set of analyses that are highly apropos to the testimony." The range of natural gas price forecasts explored by the Companies in that supplement appeared to support my contention that the Companies' gas prices were too high, but I was not given access to these new forecasts until October 17, 2011, nearly a month after I filed my testimony.

Q **Are you filing any exhibits with this testimony?**

A I have attached the following exhibits to this testimony:

- **Exhibit JIF-1:** Curriculum Vitae
- **Exhibit JIF-E2:** Net Present Value Revenue Requirement of Installing Controls vs. Retiring and Replacing Capacity: Companies' Results and Re-Analysis Results
- **Exhibit JIF-E3:** Natural gas price forecast comparisons.
- **Exhibit JIF-4:** 2011 Carbon Dioxide Price Forecast from Synapse Energy Economics, Inc.

2. SUMMARY AND CONCLUSIONS

Q **In your opinion and according to the documents you have reviewed, have the Companies adequately shown that the coal plants seeking environmental upgrades in these CPCN / Environmental Surcharge dockets merit the capital expenditures requested?**

A No, they have not. While the Companies created a generally reasonable framework for the evaluation of their existing resources and resource requirements in the face of new and emerging environmental regulations, some of the inputs into this analysis are flawed; thus tainting the analysis and ultimately the decision to maintain and retrofit units of the existing coal fleet.

In this testimony, I will describe the environmental obligations facing the Companies and briefly summarize the Companies approach to their retire/retrofit decisions in the face of those regulations. I will then discuss large-scale flaws in the input assumptions and modeling framework, results of an analysis conducted by Synapse to re-evaluate the Companies' decisions under their same framework but with revised assumptions, and the serious doubt these results cast on the

Companies' request for CPCN and environmental surcharges. I will show that several of the Companies' key assumptions inappropriately bias a retire/retrofit decision towards maintaining older coal units, and that simply using more mid-range assumptions results in a very different outcome. Finally, I will discuss additional concerns with the Companies' analysis and how these concerns might influence the ultimate retire/retrofit decisions.

Q **Please describe the Companies' framework for the evaluation of existing resources and resource requirements.**

A The Companies reasonably anticipate that existing and pending environmental regulations will require significant capital and operating expenditures at their coal fleet – expenses that could render units in the fleet non-economic to maintain. They therefore created a framework in which to evaluate the economic merit of each of their coal assets given these new expenses.

Briefly, the framework uses the Ventyx Strategist model to evaluate the net present value revenue requirement (NPVRR) of a series of retrofit and retirement scenarios. The initial baseline case estimates the NPVRR of retrofitting the entire fleet to meet environmental standards, and building new "optimal" capacity to meet requirements over a long analysis period. The Companies then estimate the NPVRR of this same scenario with the added assumption that their least economic coal unit retires in 2016, thereby avoiding the cost of expensive environmental retrofits. If the NPVRR of the case in which the unit is retired is lower than the NPVRR of the case in which the unit is retrofit, the Companies find that it is more economical to retire the unit rather than retrofit it, and the unit's retirement is assumed in the baseline.

The Companies test each of their coal assets in this method sequentially, from the most expensive operating unit to the least. Each time a unit is found to be non-meritorious, the unit is assumed to be retired and taken out of the baseline.

The Companies use this modeling process to justify environmental upgrades at KU's units Brown 1-3 and Ghent 1-4, and LG&E's units Mill Creek 1-4 and

Trimble County 1. The Companies also find that it is reasonable to retire, rather than retrofit, six of their least economic units: Tyrone 3, Green River 3 & 4, and Cane Run 4, 5, & 6.

Q **Which elements of this analysis have been incorrectly characterized?**

A The Companies have created a reasonable and transparent framework for analyzing the economic merit of retiring versus retrofitting their coal assets and have correctly characterized many of the costs faced by their fleet. However, I have significant concerns with the Companies' modeling assumptions and framework. The outcome of this analysis hinges on these assumptions, such that by simply examining a reasonable mid-range set of assumptions renders at least two additional units (Brown 1 & 2) non-economic and casts serious doubt on the economic viability of another two units (Mill Creek 1 & 2).

It is my opinion that the Companies' analysis incorrectly characterizes the following elements, each of which I will discuss in further detail later:

- **Natural gas price correction:** The Companies' base-case natural gas price forecast appears to inappropriately represent the highest end of gas price assumptions;
- **SCR cost:** The Companies have inappropriately dismissed the risk that some of its units may require selective catalytic reduction (SCR) to meet emissions limits for oxides of nitrogen (NO_x) under both promulgated and proposed ozone standards;
- **CO_2 price risk**: The Companies have assumed that there is no chance that the federal government will regulate carbon dioxide (CO_2) emissions anytime in the future, thereby exposing ratepayers to a very real financial risk;
- **Oversized replacement capacity:** The Companies assume that replacement generation is only available from three types of natural gas plants, a single-cycle turbine of 194 MW, and two combined cycle

sized at 605 and 907 MW (summer capacity), respectively. These large-size combined cycle units are larger than many of the coal units under consideration, forcing the model to only evaluate unduly expensive alternatives that present potentially non-optimal solutions.

- **Utility modeled in isolation:** The model used by the Companies assumes that they have no interactions with the Eastern Interconnection, which forces the model into unrealistic solutions.
- **Emergency generation purchases:** The model uses a very high cost for emergency generation with an unreasonably high frequency, resulting in very high costs with no apparent basis.
- **NO_x and SO_2 Prices:** The Companies have assumed that the trading price of NO_x and sulfur dioxide (SO_2) will diminish to zero in two years, in contradiction to EPA estimates; thereby denying the Companies the opportunity cost of avoiding these emissions through retirement or emissions controls.
- **Order of Retirement:** The Companies have chosen a semi-arbitrary order in which to test the retire/retrofit decision without regard to the impact that this order imposes on the modeled economic merit of each unit. Simply changing this order could result in a more optimal solution and retire/ retrofit decisions.

Q Have you evaluated how the Companies' optimal solution might change if some of these assumptions are corrected?

A Yes, my colleague Ms. Rachel Wilson re-ran the Strategist model with the Companies' assumptions and then produced alternate outcomes by using a mid-range natural gas price forecast and testing the impact of a mid-level CO_2 price forecast. I then used the Companies analysis worksheet to re-construct the decision the Companies might have made if they had:

1) used a mid-range natural gas price forecast,

2) evaluated the avoided cost of applying an SCR at several units, and

3) evaluated the risk of CO_2 regulation through a mid-range CO_2 price starting in 2018.

I calculated the outcomes of each correction both individually and in concert. I will discuss the background and results of these analyses in greater detail below. I have included these results in **Exhibit JIF-E2**. The results of changing individual variables are shown in Boxes 3-5 and the results of changing multiple variables in the same scenario are shown in Boxes 6-8.

Q Did you fix all of the assumptions that you believe are flawed?

A I did not. Due to time constraints and limited information available at this time, we did not evaluate anticipated NO_x and SO_2 prices, the impact of including appropriately-sized capacity expansion options, the effect of including electricity purchases and sales outside of the LG&E/KU system as an option, or a more optimal retirement order.

Q Did you find any other errors in the Companies' analysis?

A Yes. In the Companies' analysis workbook,[1] the avoided cost of mitigating landfill waste or coal combustion residuals (CCR) appears to incorrectly reference the year after the year of interest. I have assumed that this is in error, and corrected the formula in my re-analysis, resulting in small benefits towards the retrofit decision in some scenarios ($0-$7 million). I have propagated this correction through the remainder of my re-analysis.

Q What was the outcome of your re-analysis?

A Under each of the three scenarios listed above, the relative economic merit of the coal units declines markedly. Using the Companies' retirement order framework but using *either* a mid-range gas price *or* evaluating the cost of SCR *or* utilizing a CO_2 price makes the decision to retrofit Brown 1 & 2 anywhere from risky to a net loss ($49, $34, or -$157 million NPVRR, respectively – found in **Exhibit JIF-E2** Boxes 3-5). Using the mid-range gas price in concert with anticipated costs of SCR strongly favors the retirement of Brown 1 & 2 (a loss of $146 million NPVRR relative to the non-retirement option – found in **Exhibit JIF-E2,** Box 6).

While there are significant uncertainties associated with the future of CO_2

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[1] 20110517_LAK_2011IRPRetirementStudies_MC1-2CombinedFGD_Laye.xlsx

regulation, including shifting political climates and continued delays of meaningful national legislation, the possibility of CO_2 regulation poses a marked risk to the Companies' coal assets slated for retrofit. Utilizing a CO_2 price in concert with corrected gas prices and SCR risk, a preliminary assessment would suggest marked economic risk at all units except the Trimble County and Ghent 4 units. A more detailed analysis of this risk would evaluate the effects of a CO_2 price across the wider region electrical system, as well as ripple effects through other fuel costs.

Q What is your conclusion?

A I find that the decision to continue to invest in the Brown 1 & 2 units is not justified when either the Companies' gas or CO_2 forecasts are adjusted to mid-range values, or when the reasonable risk of an SCR at the units are considered. In general, the risk of carbon prices poses a significant economic liability for the Companies.

3. Environmental Regulations Faced by LG&E/KU

Q Is the Companies' coal fleet subject to federal laws protecting human health and the environment?

A Yes it is. The Companies' coal units are subject to EPA regulations under the Clean Air Act (CAA), the Clean Water Act (CWA), and the Resource Conservation and Recovery Act (RCRA), among other statutes.

Q Which Clean Air Act rules directly affect the LG&E/KU coal fleet?

A There are a number of regulatory areas under the CAA that directly affect the Companies' coal fleet today and in the near future, including:

- The recently finalized Cross State Air Pollution Rule (CSAPR), limiting NO_x and SO_2 emissions that contribute to poor air quality in neighboring states;
- The proposed air toxics rule for utility steam generating units ("MACT"),

designed to protect human health by reducing emissions of hazardous air pollutants (HAPs) and mercury (Hg) from oil and coal-burning units; and

- The strengthening of National Ambient Air Quality Standards (NAAQS) for SO_2 and the proposed strengthening of NAAQS for ozone (O_3), particulates ($PM_{2.5}$), and nitrogen dioxide (NO_2) designed to protect human health, reduce premature mortality, and reduce environmental harms from emissions.

Q Which Clean Water Act rules directly affect the LG&E/KU coal fleet?

A There are two CWA regulations, currently being finalized by the EPA, that the Companies should reasonably expect to affect the LG&E/KU coal fleet:

- the proposed cooling water intake structures rule, designed to protect fisheries and aquatic organisms from being trapped by cooling water screens, or uptake into cooling systems,
- and the expected effluent limitation guidelines, restricting toxic releases into waterways from steam power plant structures and effluent ponds.

Q Which Resource Conservation and Recovery Act rules directly affect the LG&E/KU coal fleet?

A The EPA is expected to finalize a rule regulating the disposal and storage of coal combustion residuals (CCR) including ash and other wastes to prevent toxic releases into ground and surface waters.

Q Have the Companies reasonably accounted for the impact of existing and proposed environmental regulations on its coal fleet?

A Yes, with a few critical exceptions, as described below.

Q Are there circumstances where you believe the Companies have correctly accounted for environmental requirements?

A There are. Assuming that the Companies are able to meet permitted emissions limits, I believe that they are correct in anticipating that all of the retrofits stipulated in KU projects 29, 34, & 35 (KU JNV-1) and LG&E projects 26 and 27 (LG&E JNV-1) would be needed to comply with environmental regulations in order to remain operational. While those controls are required if the units are going to continue to operate, they are *not necessarily sufficient.*

Q How will these projects help the Companies meet environmental requirements?

A The Brown 1-3 units have already installed a new flue gas desulfurization (FGD) system, and the Trimble County unit is already in possession of an FGD unit. Of the non-retiring units, the four units at Mill Creek are anticipated by the Companies to require new or retrofit FGD systems, which can presumably meet SO_2 compliance obligations under both CSAPR and SO_2 NAAQS. FGDs are also considered a maximum achievable control technology (MACT) for the control of acid gases under the toxics rule, have ancillary benefits in mercury control also under the toxics rule, and benefit secondary particulate control under the $PM_{2.5}$ NAAQS. The combination of fabric filter baghouses with activated carbon injection (ACI) at all of these units is also generally considered MACT for the control of mercury emissions under the toxics rule.

The proposed coal waste rule may require conversion to dry storage from wet impoundments and is likely to require the lining and closure of unlined CCR impoundments. It appears that the Companies have taken this rule into account by estimating new ongoing landfill expenditures associated with its existing coal fleet.

While not stipulated in the projects listed previously, the Companies appear to have estimated the potential costs of effluent limitation guidelines in their forward modeling as well. As noted in a discovery response to the Environmental Groups, the Companies explain that the analysis "contains the revenue requirements associated with future capital costs for complying with effluent guidelines scheduled to be proposed in late 2012." [2] These costs are apparent in the Companies' retire/retrofit model.

[2] Response to the Supplemental Requests for Information, August 18th 2011. Question 4

Q **How are the projects anticipated in this docket "required [but] *not necessarily sufficient*?"**

A What I mean is that while the Companies would need to implement these projects in order to keep the plants operational, these units will face additional environmental compliance costs on top of the ones considered. Critically, the Companies have failed to anticipate the impact of **both** the current (2008) and impending ground-level ozone NAAQS. Witness Revlett discusses SO_2 NAAQS and the Clean Air Transport Rule (CATR), the precursor to the current CSAPR rule, but makes no mention of the impending ozone NAAQS.

Q **Why are the ozone NAAQS important in this analysis?**

A It is widely believed that the ozone NAAQS is one of the most important EPA regulations in regards to the impact this standard could have on the existing coal fleet by requiring selective catalytic reduction (SCR) on numerous coal plants. It is my opinion that in failing to account for the cost of SCR, the Companies inappropriately expose customers to a known and likely environmental cost. The SCR cost risk affects several units that are requesting CPCN and environmental surcharges in these dockets, including Brown 1 & 2, Ghent 2, and Mill Creek 1 & 2.

Q **Have you examined the implications of SCR on the cost effectiveness of those units?**

A I have. I'll describe this analysis and the results later in this testimony. However, suffice it to say that the cost of SCR is high enough to render a completely different retire/retrofit decision on the Brown 1 & 2 units and significantly impact the economics of the Mill Creek 1 & 2.

Q **Are there other environmental regulations that the Companies have not taken into account in this analysis?**

A Yes. I believe that current and pending EPA regulations on greenhouse gas emissions were insufficiently addressed in this CPCN, and I will be discussing a feasible remedy later in my testimony. In addition, the Companies has made no mention of the cooling water intake structures rule which could impose significant costs on units that use once-through cooling.

Q **What is the cooling water intake structures rule?**

A On March 28, 2011, the EPA proposed a long-expected rule implementing the requirements of Section 316(b) of the Clean Water Act at existing power plants. [33 U.S.C. § 1326.] Section 316(b) requires "that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." Under this new rule, EPA set new standards reducing the impingement and entrainment of aquatic organisms from cooling water intake structures at new and existing electric generating facilities.

The rule provides that:

- Existing facilities that withdraw more than two million gallons per day (MGD) would be subject to an upper limit on fish mortality from impingement, and must implement technology to either reduce impingement or slow water intake velocities.
- Existing facilities that withdraw at least 125 million gallons per day would be required to conduct an entrainment characterization study for submission to the Director to establish a "best technology available" for the specific site.

Q **Are there any plants in the Companies' fleet that would be subject to this rule?**

A Large units that use once-through cooling are likely to exceed the 125 MGD limit. According to information reported by the Companies to the US Department of Energy (DOE) Energy Information Administration (EIA) in 2009 (Form 860), the Tyrone 3, Cane Run 4-6 units, and Mill Creek 1 unit all use once-through cooling.

The company plans to retire Tyrone 3 and the Cane Run units regardless, but the Mill Creek 1 unit would still be a concern for this rule.

According to independent research at the National Renewable Energy Laboratory (NREL),[3] once-through coal-fired units withdraw between 20,000 to 50,000 gallons per MWh of energy. According to information supplied by the Companies in discovery,[4] Mill Creek will output upwards of 2,200 GWh on an annual basis through the end of the analysis period. At this output, I would estimate that the unit would withdraw between 120 and 300 MGD. I assume that the Companies have access to data to know if the unit would be subject to the more stringent entrainment guideline.

Q If Mill Creek 1 were subject to the entrainment guidelines of this cooling water rule, how might that affect their economic merit?

A The cooling water intake rule is designed to reduce impacts associated with once-through cooling. It is likely that the compliance mechanism for high withdrawal units will require retrofits to cooling towers as the "best technology available" where feasible. These cooling towers can be expensive. Using cost assumptions from a North American Reliability Council (NERC), I estimate the cost of a cooling tower for Mill Creek Unit 1 at around $70 million. However, it is my opinion that it is incumbent on the Companies to evaluate the risk that the unit will be subject to the rule and estimate the cost of compliance.

4. Synapse Retire/Retrofit Re-Analysis

Q How have the Companies determined which units to retrofit with environmental controls?

A The Companies have made the overarching assumption, appropriately, that they should consider the economic merit of retiring some coal units rather than retrofitting them to meet stringent environmental regulations. The Companies

[3] National Renewable Energy Laboratory. March, 2011. A Review of Operational Water Consumption and Withdrawal Factors for Electricity Generating Technology. http://www.nrel.gov/docs/fy11osti/50900.pdf

[4] Confidential Attachment to Response to KU KPSC-1 Question No. 37, p3

determined that all coal units operating after 2016 would have a broad set of environmental obligations (and therefore costs). From an economic perspective, it would be efficient to operate the existing coal fleet up to the first high-cost compliance deadline, and then take out of service any units which are non-economic at that time.

To determine whether to retrofit or retire each unit in their fleet, the Companies examined the net present value revenue requirement (NPVRR) of maintaining and retrofitting each unit versus retiring the unit in the year 2016 and replacing the capacity with natural gas fired generation.

Q **How do the Companies determine the NPVRR of each case?**

A The Companies use the Ventyx Strategist model to determine a reasonable build-out through 2040 under each of their test cases. The model is first run for a case in which all existing coal units are retrofitted as required to remain operational (the "no retirements" case). The net production and new unit capital cost from this run is compared against a case in which a high-variable cost coal unit is retired in 2016. If the total NPVRR of the no-retirement case is higher than the retirement case (including avoided capital costs),[5] then the retirement case is considered more efficient and the Companies assumes that they will retire the unit. Otherwise, the Companies assume that they will retrofit the unit under consideration. If the unit is retired, the new base case (by which the next unit is tested) includes the previous unit's retirement.

Q **Were you able to replicate the Companies' modeling results?**

A We were able to replicate the Companies' originally filed results. Synapse obtained the Strategist model inputs from the Companies and the Companies' spreadsheet-based analysis. My colleague Ms. Wilson licensed an identical build of the Strategist model as used by the Companies from Ventyx and re-ran the

[5] The retirement cases include the avoided costs of the environmental capital expenditures and fixed O&M, and a single-year cost adder to decommission retiring units.

model with the same inputs. Using identical input, we were able to obtain the same results as the Companies.

The Companies' originally filed results are shown in **Exhibit JIF-E2** Box 1. These values are also found in the Companies' direct testimony in Exhibit CRS-1, Table 2, in the column entitled "Difference (A)-(B)."[6] These values are the NPVRR difference, relative to a no retirement scenario of retiring each unit in a cumulative fashion as described above and in the Companies' direct testimony.

The Companies find that it is economically efficient to retire the units with negative NPVRR values relative to a "no retirement" scenario. These units include Tyrone 3, Green River 3 & 4, and Cane Run 4 & 5. The Companies determined that, although the NPVRR value is marginally above zero, retrofitting Cane Run 6 presents too high of a risk and has opted to retire this unit as well.

In **Exhibit JIF-E2** Box 2, we have corrected a formula error in the Companies' analysis that references an incorrect year, as described in the summary of this testimony. This correction is maintained through the re-analysis results, and favors the retrofit decision by $0-$7 million.

Q Does the Companies analysis have any flaws?

A As I identified in the summary section, the analysis had a number of flaws, some of which are unquestionably significant enough to completely change the analysis outcome. Therefore, it was important to conduct a re-analysis with corrected assumptions to estimate how retire/retrofit decisions would change under a reasonable set of assumptions.

Q How did you perform a re-analysis?

A As noted above, we used the Companies' build of Strategist and model inputs provided in discovery (Environmental Groups DR 3) to re-run the analysis. We used the Companies broad arching assumption of the order in which units are

[6] As noted in a commission staff discovery request, this column should be labeled "Difference (B) – (A)"

tested for economic merit, but *for internal consistency with the Companies, did not pull any additional units out of the analysis if they were deemed non-economic.*

The re-analysis examined three fundamental aspects of the Companies' analysis:

- **First,** we corrected the Companies' natural gas price forecast to reflect a mid-range estimate as provided by the Companies;
- **Second,** we added the Companies' estimated capital and operating costs of SCR at the Brown 1 & 2, Ghent 2, and Mill Creek 1 & 2 units into the avoided cost analysis;
- **Third,** we tested the impact of a mid-range CO_2 price on the decision to retire or retrofit.

We examined each of these adjustments *independently* and in concert.

The method and justification for each of these changes is described in detail in the sections below.

5. GAS PRICE CORRECTION

Q Is the Companies' gas price forecast consistent with other forecasts?

A The Companies have presented a range of gas price forecasts throughout this proceeding. The original forecast supplied by the Companies was outside the bounds of natural gas prices reflected by most other analysts.

Q Have the Companies provided alternative fuel price forecasts?

A Quite recently, yes. On September 14th, the Companies provided Supplemental analyses exploring the retire/retrofit decision with three more recent and lower price forecasts from PIRA Group, Wood Mackenzie, and IHS CERA, but did not provide the fuel forecast values. On October 17th, the Companies finally supplied the gas price forecasts from these three sources. Finally, in rebuttal testimony filed October 24, the Companies provided definitive information that their original forecasts were presented in nominal dollars and definitive information about the expected inflation rate for fuel costs,[7] thus partially explaining a large deviation from mid-range estimates. We have assumed that this same inflation rate, amounting to approximately 2.18% per year, applies to the other fuel price forecasts as well.

Q **Are the alternative gas price forecasts consistent with others' forecasts?**

A Yes. When the 2.18% inflation rate is removed from the PIRA, Wood Mackenize, and CERA prices, the real value of these forecasts appears to fall within the range of other analysts' estimates. As shown in **Figure 1**, below (and in **Exhibit JIF-E3**, page 1), we show the Companies' original estimate of the Henry Hub (HH) price in red triangles,8 a variety of publicly available forecasts for the HH price,9, 10, 11,12,13,14,15,16, and the Companies' proprietary, alternative forecasts (PIRA, Wood Mackenzie, and CERA) in shades of orange.

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[7] Annual deflators for fuel, as used by the Companies, are given in rebuttal witness Sinclair's workpapers. Converting from nominal to real dollar values; the net impact amounts to an annually compounding interest rate of approximately 2.18%. The Company appears to use 2.5% inflation rate for capital expenditures, 2% for variable O&M costs (and in the conversion of a provided CO_2 price) but does not inflate the emergency energy cost in the model, leaving it at $16,600 / MWh in each year.

[8] Found in Attachment to Response to SC/NRDC Production of Documents Question No. 16. *2011 Air Compliance Plan Sensitivity Analysis. July 2011*

[9] US DOE Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2010 Reference Case

[10] US DOE Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2011 Reference Case

[11] Northwest Power and Conservation Council (NWPCC), August 2011. Update to Council's Forecast of Fuel Prices (pg 6-7)

[12] Globex Futures from CME Group Henry Hub Natural Gas Futures, Trade Date 9/12/2011 (2011-2023) Settlement Price. http://www.cmegroup.com/trading/energy/natural-gas/natural-gas_quotes_globex.html

[13] Eastern Interconnection Planning Collaborative (EIPC). Working Draft of MRN-NEEM Modeling Assumptions and Data Sources for EIPC Capacity Expansion Modeling. December 22, 2010. Charles River Associates. Hi Gas Henry Hub Price.

[14] Navigant Consulting, August 2010. Market Analysis for Sabine Pass LNG Export Project. http://www.navigant.com/~/media/Site/Insights/Energy/Cheniere_LNG_Export_Report_Energy.ashx

[15] RGGI and EPA prices extracted from EIPC Fuel and Emission Prices Subteam January 12 Report.

[16] Avoided Energy Supply Component (AESC) Study Group, July 2011. Avoided Energy Supply Costs in New England: 2011 Report. http://www.synapse-energy.com/Downloads/SynapseReport.2011-07.AESC.AESC-Study-2011.11-014.pdf

[redacted]

Figure 1. Henry Hub Natural Gas Price Comparisons: Companies Estimate, Other Analyst Forecasts, and Re-Analysis Forecast (AESC 2011)

Expressed here in constant 2010$, the Companies' alternative forecasts appear to represent a reasonable range of high, mid, and low gas price forecasts.

Q **Is it reasonable to use a high, mid, and low gas price forecast?**

A It is. The use of a range of forecasts can help elucidate risk posed in an uncertain future. However, the Companies have chosen the highest of those prices to represent their "base case." It appears that the Companies' natural gas price forecast is at the high-end of the range of forecasts given by other public and private entities.

Q **Which natural gas price forecast did you use in your re-analysis?**

A In the initial form of this direct testimony, we had used a natural gas price forecast from the Avoided Energy Supply Component (AESC) Study Group in 2011. The AESC report is sponsored by a group of electric utilities, gas utilities, and other efficiency program administrators throughout New England and was written by consultants at Synapse Energy Economics, Inc, as well as other experts.

The Companies released their alternative natural gas price forecasts in the

October 17th Supplemental Analyses. Of the three alternatives presented, the Wood Mackenzie price is most consistent with the AESC baseline forecast, and appears to represent a reasonable mid-range forecast. Therefore, we have chosen to simplify the record by adopting the Wood Mackenzie price from the Companies' series of alternatives.

Q **Would it still be reasonable to use the AESC forecast of natural gas prices as a mid-range forecast?**

A Yes.

Q **Please describe how you used the Wood Mackenzie natural gas price in the Strategist model.**

A The Strategist model accepts natural gas prices in \$/MCF,[17] and in addition, it is apparent that the Companies have added a transportation or local price adjustment to the HH forecast and have set up the model to read gas prices as the highest annual monthly-average gas price. To adjust the Wood Mackenzie HH price to a burner-tip equivalent, we used a short conversion:

First, we converted Strategist input prices back to \$/MMBtu. Second, we extracted the seasonal gas price adjustment factors used by the Companies to adjust from the highest price month to monthly prices. We obtained the average of these factors on an annual basis (2010-2025), assuming that the average roughly represents the deflator from the highest price month to the annual average price. Next, we adjusted the "high" delivered price forecast (in \$/MMBtu) to the annual average price, and examined the difference between this price and the Companies' Henry Hub forecast (p. 4 of the Sensitivity Analysis[18]). We assumed the resulting \$0.35 to \$0.40 adder was the local price adjustment from HH. This cost is similar to the premium estimated by the EIA for electric generation in East South Central

[17] The prices in the model, in \$/MCF, replicate those given in the "Attachment to Response to KPSC-1 Question No. 44" which are listed as fuel costs in \$/MMBtu. It is assumed that the units in model, rather than the discovery response, are correct.

[18] Found in Attachment to Response to SC/NRDC Production of Documents Question No. 16. *2011 Air Compliance Plan Sensitivity Analysis. July 2011*

region (including KY) relative to HH in 2010.

We then reversed this process for the Wood Mackenzie HH price, adding the delivery charge, dividing by the seasonal adjustment factor, and converting back into $/MCF. This revised value was exported back to the Strategist model.

Retaining consistency with the Companies' assumptions, we held the nominal price of the Wood Mackenzie HH forecast constant from 2025 through the end of the analysis period, as shown in the Wood Mackenzie line of **Exhibit JIF-E3**, on page 2.

Q **Were you able to reproduce the results given by the Companies in the October 17th Supplemental Analyses?**

A We were not able to replicate the results exactly. As shown in Table 1, below, we obtained similar, but not exact results. The tables below are similar to those shown in **Exhibit JIF-E2**, where each value represents the relative net present value of installing controls versus retiring and replacing capacity. The Companies' results, from the October 17th Supplemental Analyses are shown in the first box, while Synapse's re-analysis, using the same data, are shown in the middle box. The third box shows the difference between these two analytical results.

Table 1. Difference in NPVRR (2011$) between Companies' Supplemental Analysis and Synapse Re-Analysis using Wood Mackenzie 2011 price forecast.

KU/LGE Supplemental Analysis		Synapse Re-Analysis		Difference	
Table 5 - PVRR of Installing Controls vs. Retiring and Replacing Capacity		Nominal Wood Mackenzie Gas Price*		Synapse minus KU/LGE	
Tyrone 3	-10	Tyrone 3	-59	Tyrone 3	-49
Green River 3	-88	Green River 3	-66	Green River 3	22
Brown 3	357	Brown 3	368	Brown 3	11
Cane Run 4	-187	Cane Run 4	-240	Cane Run 4	-53
Cane Run 6	-145	Cane Run 6	-67	Cane Run 6	78
Brown 1-2	39	Brown 1-2	49	Brown 1-2	10
Cane Run 5	-171	Cane Run 5	-193	Cane Run 5	-22
Ghent 3	520	Ghent 3	529	Ghent 3	9
Ghent 1	400	Ghent 1	430	Ghent 1	30
Green River 4	-140	Green River 4	-130	Green River 4	10
Mill Creek 4	481	Mill Creek 4	484	Mill Creek 4	3
Trimble County 1	675	Trimble County 1	654	Trimble County 1	-21
Ghent 4	750	Ghent 4	727	Ghent 4	-23
Mill Creek 3	453	Mill Creek 3	423	Mill Creek 3	-30
Ghent 2	755	Ghent 2	728	Ghent 2	-27
Mill Creek 1-2	536	Mill Creek 1-2	530	Mill Creek 1-2	-6

We were not given the Companies workpapers, and so do not know why our results are not identical to the Companies, but it is possible that we may have adjusted the Henry Hub gas price to a local gas price using a different formulation than that of the Companies or used a different coal price than the Companies.[19] Regardless, there are no directional changes in our re-analysis, but there are changes in the magnitude of benefit realized through the retirement or retrofit of any given set of units.

Q Did adjusting the gas price forecast make a difference in the re-analysis of the Companies' results?

A Yes. By adjusting the natural gas price forecast to a reasonable mid-range estimate, the relative benefit of maintaining any of the coal units diminishes significantly, but is particularly notable at Brown 1 & 2. As shown in **Exhibit JIF-E2** in Box D, the NPVRR benefit of maintaining Brown 1 & 2 falls from $228 million to $49 million (or $39 million by the Companies' calculation). In other words, the re-analysis with a mid-range gas price would suggest that Brown 1 & 2 are a high risk for continued operation. While a lower gas price alone does not *a priori* render these units non-economic, I believe that other faults in Company assumptions quickly erode the remaining margin, including the inflated emergency energy cost assumptions (discussed later in my testimony).

Costs for SCR at Brown 1 & 2, Ghent 2, and Mill Creek 1 & 2

Q In the summary, you stated that the Companies have not anticipated the impact of the impending ground-level ozone NAAQS. Does this shortcoming have an impact in the Companies assessment of the retire/retrofit decision?

A Absolutely. By ignoring the impact of both current and proposed ozone NAAQS, the Companies ignore the high cost of mitigating ozone; costs that the companies reasonably face in the near future. One of the most effective mechanisms for reducing ozone pollution is by controlling NO_x emissions at stationary sources.

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[19] Synapse maintained the original coal price forecast used by the Companies in the 2011 Compliance plan.

through installing Selective Catalytic Reduction (SCR) technology. This technology has a high price tag, and, if required, could feasibly alter the retire/ retrofit decision at some of the Companies' coal-fired units.

Q What are the ozone NAAQS?

A EPA promulgates NAAQS pursuant to the authority granted by Clean Air Act § 109 (42 U.S.C. §7409). EPA sets primary NAAQS to protect public health and secondary NAAQS protect public welfare. The NAAQS are supposed to be evaluated and revised, if necessary to protect public health and welfare, at five year intervals. New standards for ozone (and other criteria pollutants) will trigger the process for designating areas as either in "attainment" or "nonattainment" with the new standards. In nonattainment areas, sources must *automatically* comply with emission reduction requirements known as "Reasonably Available Control Technology" (RACT), and new sources, including major modifications at existing sources, must comply with very strict emissions reductions consistent with "lowest achievable emissions reductions" (LAER), as well as obtain emission offsets.

Q Are Kentucky counties likely to be in "nonattainment" with respect to the ozone NAAQS?

A The current ozone standard, promulgated on March 12, 2008 (73 Fed. Reg. 16,436 (March 27, 2008)) set the ozone NAAQS at 0.075 parts per million (ppm). According to estimates released in January 6, 2010, thirteen counties in Kentucky violated the current standard between 2006-2008.[20]

The EPA proposed a stringent new ozone standard on January 19, 2010 (75 Fed. Reg. 2,938 (Jan. 19, 2010)), reducing the standard from 0.075 ppm to between 0.060 and 0.070 ppm, a move which could cause 25 counties in Kentucky to violate the new standard, according to 2006-2008 data.[21]

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[20] US EPA. 2010. Counties Violating the Primary Ground-level Ozone Standard, 2006-2008. http://www.epa.gov/glo/pdfs/CountyPrimaryOzoneLevels0608.pdf

[21] US EPA. 2010. Counties Violating the Primary Ground-level Ozone Standard, 2006-2008. http://www.epa.gov/glo/pdfs/CountyPrimaryOzoneLevels0608.pdf

Q Will EPA promulgate the new ozone NAAQS this year?

A Although EPA was due to finalize the new ozone NAAQS by July 29, 2011, this was pushed back by an executive review. On September 9, 2011, the EPA announced that it was holding off on the promulgation of this rule until 2013. This delay will likely face a court challenge.

It is my opinion that the rule will be delayed by two years, either due to the impending legal obstacles or by administrative fiat, but ultimately EPA will promulgate the new ozone NAAQS due to the EPA's legal responsibility to protect public health.

Q Is this a reasonable opinion given EPA's recent action?

A Yes. The law unequivocally requires EPA to review the NAAQS standards every five years to ensure that they provide adequate health and environmental protection, and to update those standards as necessary to protect public health. EPA is set to review the ozone NAAQS standard in 2013. If EPA has not promulgated a standard by then, it must certainly do so then as the Clean Air Scientific Advisory Committee found that a standard between 0.060 to 0.070 ppm is absolutely needed to protect public health. The CAA does not authorize EPA to consider the cost of achieving a NAAQS in establishing the standard. Therefore, my opinion that EPA will promulgate a new ozone NAAQS in the near future is quite reasonable.

Q. How will a new ozone NAAQS impact the LG&E/KU fleet?

A Of particular importance to the LG&E/KU fleet, the four coal plants which are anticipated to continue operation (Ghent, Trimble County, Mill Creek, and Brown) are all either in, or immediately adjacent to counties which violate even the least rigorous of the proposed standards (see Figure 1, below)

Figure 2. Counties With Monitors Violating Primary 8-hour Ground-level Ozone Standards 0.060 - 0.070 parts per million (based on 2006-2008 Air Quality Data). Kentucky detail, Modified from EPA.[22]

While there is no guarantee that these counties will still violate the standard when the rule is promulgated, these regions have poor air quality that will require significant reductions to meet the more stringent limit. Also, it is often the case that air quality managers find the most cost effective air quality reductions by controlling large, uncontrolled stationary sources – such as coal plants.

Ozone is a secondary pollutant formed from NO_x emissions and other ambient volatile compounds. One of the most cost-effective methods of reducing ozone pollution by requiring large-scale NO_x reductions at large power plants through the implementation of SCR.

I believe that when EPA implements this NAAQS, there is a risk that operational plants that do not have SCR will require this control technology (Brown 1 & 2, Ghent 2, and Mill Creek 1 &2), to meet local attainment.

Q What action should the Companies take in regards to the ozone NAAQS?

A The Companies should evaluate the costs and reasonable risk that these units will need to install SCRs to remain compliant with the law in their forward modeling.

Q Have the Companies evaluated the cost of SCR at the uncontrolled units?

[22] US EPA, 2010. http://www.epa.gov/glo/pdfs/20100104maps.pdf

A In April 2010, the Companies comprehensively examined the environmental regulations faced by their coal fleet, including that of the ozone NAAQS. In the E.On US Fleetwide Assessment (attached to Exhibit JNV-2 as Appendix A, the file "Complete Appendix A" therein), the Companies notes both ozone revised NAAQS as well as new NO_x NAAQS standards impending shortly that could impact the fleet. Indeed, in regards to Brown 1 &2, for example, the Companies stated as part of the full report (p 4-3) filed in April that

> to meet the identified pollutant emissions limits, new AQC technologies are required for Brown Unit 2. These AQC technologies include the installation of new SCR and PAC injection.... The new SCR system can reduce NOx emissions to 0.11 lb/MMBtu or lower.

The Companies similarly stated that Ghent 2 and Mill Creek 1 & 2 would also require SCR (p 4-16, and 4-28, respectively).

As part of this analysis, the Companies evaluated the costs of SCR at Brown 1 & 2, Ghent 2, and Mill Creek 1 & 2, and had decided by May 2010 to pursue SCR as part of the suite of environmental controls required at their units. In the Environmental Air Compliance Strategy Summary (Exhibit JNV-1, p3), the Companies state:

> Installing SCRs was the most cost effective, reliable and efficient option for B&V to estimate. Low NOx burner and OFA [overfire air] installations have already been installed on most of these units on past projects. The small gains in burner technology since these past modifications were installed would impact NO_x emissions, *but not at a level that would consistently meet the requirements of pending regulations.* [emphasis added]

However, in "late 2010", "the Companies' Energy Planning, Analysis and Forecasting department's first round of modeling indicated that the

SCR's... identified in the Phase I and II studies would not be necessary to meet the CATR NO_x emissions reductions for the generating fleet." (Exhibit JNV-1 p8). This claim is repeated in Witness Voyles direct testimony, that simple modifications to existing infrastructure "defer[s] the need for additional SCR installations and support[s] least-cost compliance with the proposed CATR, which will impose stricter NO_x emissions requirements on LG&E and KU."

The stipulation that the CATR (the Transport Rule) is the only pending regulation which will require NO_x reductions is flawed because, as noted above, I believe that the ozone NAAQS will require SCR on the Companies coal plants.

The Companies examined this possibility in the 2011 Air Compliance Plan Sensitivity Analysis (p6), stating:

> Because more stringent NO_x emission reduction requirements in the future could require the construction of SCRs on some or all of these units, the Companies considered the cost of potential future controls and whether these costs could be incurred without changing the Companies' current recommendation.

Q ***Did the Companies provide the costs of SCR at their uncontrolled plants?***

A Yes. The Companies provided their estimated streams of capital and operating expenses for SCR at Brown 1 & 2, Ghent 2, and Mill Creek 1 & 2 in discovery, and we were able to incorporate these costs into the Companies' modeling structure as part of the re-analysis, as if the SCR came online in 2018.

Q **What is the result of the re-analysis examining the additional cost of SCR at these stations?**

A In our re-analysis, only the three unit blocks of Brown 1 & 2, Ghent 2, and Mill Creek 1 & 2 are affected by the decision to add SCR, or more specifically realize a significant avoided cost of SCR by retiring, rather than retrofitting these units. The results of this analysis are shown in **Exhibit JIF-E2,** Box 4. The NPVRR of retrofitting Brown 1 & 2 shrinks from $230 million to $34 million, and both

Ghent 2 and Mill Creek 1 & 2 move from over a billion dollars of benefit to about $800 million benefit each.

The $34 million net benefit remaining at Brown 1 & 2 once SCR is required—assuming the company's gas price is correct— is a narrow margin upon which to base a decision to retrofit and maintain this unit. At about 1% of the total NPVRR of the total system cost, this narrow window could easily be violated by uncertainties in the model, forecast fuel and emissions prices, or capital requirements.

This component of the re-analysis alone should cause the Companies to reconsider their decision to retrofit the Brown 1 & 2 units.

Q What is the result of the re-analysis examining the additional cost of SCR *and* the mid-range gas price at these stations?

A Combining the mid-range gas price re-analysis and the avoided cost of not building SCR at these stations has a dramatic impact on the retire/retrofit decision. The results of this analysis are shown in **Exhibit JIF-E2**, Box 6. Our re-analysis indicates that retrofitting Brown 1 & 2 would result in a NPVRR *loss* of $146 million to the Companies, and is an inefficient solution.

The Ghent 2 and Mill Creek 1 & 2 units are also diminished in benefit to $441 and $270 million NPVRR relative to a retirement decision, significantly down from the billion dollar benefit suggested by the Companies' original analysis (**Exhibit JIF-E2**, Box 1).

7. Carbon Mitigation Risk

Q Does the Companies' model address the risk of carbon dioxide emissions mitigation?

A No. The Companies make no reference to recent legislative proposals to mitigate carbon dioxide (CO_2) emissions or to the existing Greenhouse Gas Tailoring Rule, finalized in May 2010, which requires that projects that increase GHG emissions substantially obtain air permits that regulate these emissions. These actions could reasonably impose a cost on the emissions of CO_2.

Q **Are any of the carbon dioxide risks currently applicable or is future legislative or regulatory action required before the risk exists?**

A Current regulations impose a risk on the Companies' fleet of coal-fired power plants. Under the Greenhouse Gas Tailoring Rule, if a modification to a power plant will cause an increase in greenhouse gas emissions of 75,000 tons per year and the total emissions from the plant exceed 100,000 tons, then the plant must control its greenhouse gas emissions with the best available control technology (BACT). The Companies anticipate in the "no retirements" Strategist run that some of their coal units—units that are receiving major environmental modifications—would increase GHG emissions beyond this threshold in the next few years. Therefore, it was completely unreasonable for the Companies to not address this regulation.

Q **Why does the Companies' lack of a CO_2 price represent a risk to ratepayers?**

A The vast majority of scientists who study climate change and climate change impacts, myself included, have concluded that unabated greenhouse gas emissions, particularly emissions of CO_2, pose an extraordinarily large risk to human societies and economies. These risks and costs will become increasingly obvious in the coming years and decades as the damages to communities, ecosystems, and species mount. This risk cannot be addressed without significant reductions in CO_2 emissions, a large share of which come from the power sector. Assuming federal policy will ultimately address this problem, at some point in the not-too-distant future, coal-fired power plants will be required to either cease operations or make capital investments to capture and permanently store CO_2 emissions (using technology whose nature and cost are not known today), or pay others to do so in their stead. Power producers will likely realize these regulations as a cost imposed on CO_2 emissions.

Due to the increasingly contentious politics associated with regulating CO_2 and other greenhouse gases, it is uncertain when such regulatory or legislative actions might occur. However, if the weight of evidence does eventually prevail, it is my opinion that there will be no choice but to find mechanisms to reduce CO_2 emissions; those actions would almost certainly impose costs on sources with large CO_2 emissions, such as coal-fired power plants.

The Companies' failure to address CO_2 risk results in no carbon price at all. It is my opinion that this is an extremely unlikely scenario, and this failure to plan for a likely significant future costs poses a major regulatory risk for LG&E/KU customers.

Q ***Have you evaluated how a reasonable CO_2 cost could impact the Companies' decision to retrofit versus retire units of their coal fleet?***

Yes. I have conducted a re-analysis of the Companies' plan implementing a mid-range CO_2 price as forecast by my firm, Synapse Energy Economics, attached as **Exhibit JIF-4**. The Synapse forecast was produced in February of 2011, and represents the marked uncertainty in how and when greenhouse gas prices might apply. The forecast is a public document explaining background, state and regional initiatives, analytical estimates, and the recommended Synapse 2011 CO_2 price forecast for planning purposes.

For the purposes of this case, I have tested the re-analysis with the Mid, or Expected, CO_2 Price Forecast. This CO_2 price starts at $15/ton (2010$/short ton) in 2018 and climbs to $50/ton in 2030. The levelized cost is $26/ton over the period 2015-2030.

I used a straight-line extrapolation to extend the Synapse Mid CO2 price through 2040, and adjusted the price from constant 2010$ to nominal dollars at the 2.18% inflation rate consistent with the Companies effective natural gas price inflation rate (see rebuttal witness Sinclair workpapers). Sierra Club witness Ms. Wilson incorporated these CO_2 prices into the re-analysis.

Q **Are the CO_2 prices you used in the re-analysis similar to CO_2 prices utilized by the Companies in the past?**

A Yes. In the Companies' 2008 IRP they included CO_2 pricing in their modeling. The Companies utilized an intermediate and high carbon price, similar in magnitude to our price estimate. The Companies noted that it needed to account for these costs because of risks associated with future regulation or legislation.

Q What are the results of implementing the CO2 price on the retire/retrofit decision?

A As with the corrected gas price analysis, a CO_2 price tends to favor gas replacement relative to coal, therefore drawing down the NPVRR benefit of maintaining any units in the coal fleet. **Exhibit JIF-E2,**, Box 5 shows the effect of using *only* the Synapse Mid CO_2 price on the NPVRR of each retire/retrofit decision, leaving the Companies' original gas and SCR assumptions intact. Imposing the Synapse Mid CO_2 price results in an economic loss at Brown 1 & 2 of $157 million, at Mill Creek 1 & 2 of $20 million, and even Ghent 1 of $4 million.

Using a mid-range gas price provided by the Companies', and imposing a CO_2 price risk on the fleet, the retrofit/retire decision changes for much of the fleet under consideration – barring Trimble County 1, Ghent 4, and Ghent 2, all of the other units are rendered non-economic relative to the Strategist replacement options (see **Exhibit JIF-E2,**, Box 7).[23]

Finally, applying all three revised assumptions to the model results in an apparent non-economic performance of all but the Trimble County 1 and Ghent 4 units (see **Exhibit JIF-E2,**, Box 8).

8. Re-Analysis Findings

Q Would you summarize your re-analysis findings?

[23] By the same virtue that the net benefit of maintaining Brown 1 & 2 with an SCR only assumption (Box 4) might be considered a solution "in the noise" at $34 million NPVRR, the retirement of Ghent 3 and Mill Creek 3 in this scenario (at -$24 and -$43 million, respectively) might also be considered "in the noise". Clearly, should a CO_2 price be implemented, the regional impact would be significant and thus these retirements should be considered within the context of regional changes as well.

A I stipulate that while the Companies have constructed a reasonable and thoughtful approach to evaluating the retrofit/retire decision for each of their coal units, basic fundamental inputs into the Companies' model are flawed, tainting the analysis and ultimately exposing ratepayers to unnecessary risk. Any one of these three flaws—gas price forecast, SCR requirements, or the risk of a CO_2 price—demonstrates that some of the units for which LG&E/KU is requesting CPCN and an environmental surcharge are not economic.

Using any two of these corrections in concert dramatically changes the Companies' decision to retrofit *at least* the Brown 1 & 2 units, and calls into serious question the cost-effectiveness of upgrading other coal units as well.

The risk that the Companies will be exposed to by a CO_2 price is by no means *de minimis,* and yet in this analysis, the Companies has failed to review this risk – much less assessed how it could change the forward-going economics of their coal fleet.

I find that the Brown 1 & 2 unit retrofit is a high risk, and likely a net loss under reasonable mid-range assumptions, and that the Companies' gas price and CO2 assumptions overstate the benefit realized by maintaining these units.

9. Additional Analytical Concerns

Q Are there other problems or concerns that you've identified in the Companies' modeling in this case?

A There are. I have concerns with:

- the large-block capacity additions,
- the lack of transactions with other companies,
- emergency energy costs,
- the order in which units are chosen for retirement, and
- the Companies' assumed SO_2 and NO_x prices.

Q Please explain what you mean by "large-block" capacity additions, and why that is a concern.

A Central station power plants are constructed in discrete sizes. This can present challenges for system planners, in that capacity additions may result in excess capacity for some period of time, and related challenges in terms of planning analysis and modeling.

In this case, the gas combined cycle plant that is called upon in the Strategist model in or around 2016 is roughly 1000 MW in capacity. This is quite large for a system the size of LG&E/KU, which has an annual peak demand of about 7000 MW.

The graph shown in **Figure 3**, below, illustrates the "large-block" issue in two different cases – in red, the case in which there are no retirements and in green, the "maximum" retirement case where Tyrone 3, Green River 3 & 4, and Cane Run 4-6 are all retired in 2016.[24]

- In the "no retirements" case, a single 1000 MW 3x1 unit is built in 2017, exceeding the capacity requirement by 700 MW in the first year, and leaving an overbuilt system through at least 2022.
- In the Companies' "maximum retirements" case,[25] the total capacity of retired units works out to exactly the rated capacity of the 3x1 gas unit, and thus there is nearly a perfect replacement in 2016. Thereafter, the supply echoes the "no retirements" scenario, offset by one year.

[24] Scenario using Companies assumptions.

[25] Not named as such by the Company, but the scenario in which Tyrone 3, Green River 3 & 4, and Cane Run 4-6 are all retired.

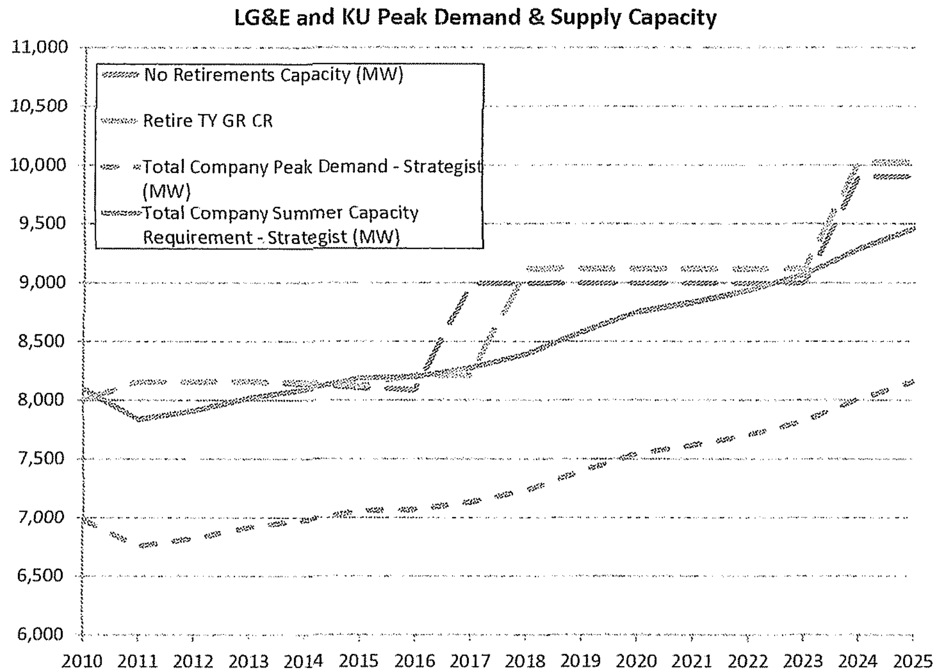

Figure 3. Peak demand, summer capacity requirement (assuming 16% target reserve margin), and supply in two retire/retrofit cases.

The Companies' chosen modeling constraints that require the system to be overbuilt by large margins is what I mean by "large-block" problem.

Q How does the "large-block" issue impact the retire/retrofit decision?

A There is a large mismatch between the size of the commonly chosen 3x1 gas CC and the coal units available for potential retirement. One of the confounding circumstances that occurs is when a small unit is retired, or considered for retirement, but there are only large units available for replacement.

For example, take the case of the "maximum retirements" case above, where the combination of six retiring units in 2016 works out to exactly the size of a 3x1 gas CC, and thus a "perfect" replacement. The next unit that the Companies analyze is Mill Creek 4, which is 544 MW. The model chooses to build two 3x1 CCs in 2016 to make up the gap, overbuilding by 363 MW, and advancing a large capital expenditure forward by two years (from 2018 to 2016), which would inflate the

NPVRR of this scenario unnecessarily.

Q What can be done about this "large-block" issue in modeling, and in actual system expansion?

A In conducting utility system planning it makes sense generally for the capacity addition options to have a resemblance in size to the particular capacity decisions being made, and to maximize flexibility where feasible in the system. In other words, if the focus of the analysis is upon coal units sized at about 100 MW then you can minimize the large-block problems by offering the model replacement capacity additions available in 100 MW size. Also, it is informative to look at capacity increments in terms relative to annual load growth. In this case, the annual load growth projected by the Companies, and input to Strategist, is about 100 to 200 MW per year. So capacity additions of 1000 MW represent anywhere from five to 10 years of load growth. It is, in my opinion, more reasonable for modeling purposes to have multiple additions that represent two or three years of load growth, so that the model results are smoother and less subject to erratic noise caused by the large additions of unneeded capacity in a particular year.

In the actual system expansion, adding more reasonably sized increments of capacity can help to avoid having customers pay for excess capacity for long periods of time, and the rate shock and economic issues that it can engender. One way that utilities can avoid these problems (in modeling and in actuality) is to share capacity additions. If a 1000 MW combined cycle plant truly offered significant efficiencies or economies of scale, then perhaps two companies could partner and co-own the construction project of such a plant. Indeed, there are likely many utilities across Kentucky and the larger region that are facing similar, if not identical, retrofit/retire decisions as the Companies, and on the same timescale. In this case, the Companies should consider modeling incremental shares of a large, cost effective natural gas plant, as if it were to be a shared expense with other utilities in similar positions.

Q Are there other issues of concern with the large replacement units available in the Strategist model?

A Yes. The model inputs suggest that the 3x1 CC units are rated at 1009 MW, but provide only peak capacity of 907 MW, an unusually large de-rating for a new and ostensibly quite efficient unit.

Also, results from the Strategist model, provided by my colleague Ms. Wilson, suggest that these very large CC units are run at extremely low capacity factors – 25% to 33%, or well below what is expected from a baseload-capable unit. While we have not had the opportunity to explore these issues yet in greater depth, intuitively it seems as if a combination of fewer gas CC units and either peakers or additional demand response (or both) could provide a more cost-effective capacity and energy replacement.

Q What do you mean when you say that there is a problem with a "lack of transactions with other companies"?

A Well, the problem is really that the Companies' Strategist model treats its system in nearly complete isolation from neighboring utilities and other generators in the region. In reality, the Companies are very well interconnected with their neighbors and the investment in the transmission that makes that possible is in rates that their customers pay.

Q How would participation in the broader regional system influence the economics of retiring specific coal-fired power plants?

A In general, the availability of purchasing energy from others, either bilaterally or through MISO markets, would present additional resources that could play a part in the energy mix replacing the generation that would otherwise have come from the retired units over *at least* short periods of time or for fairly limited capacity requirements. By modeling its system in isolation in Strategist, the Companies have unrealistically restricted the range of potential sources of replacement energy, therefore encumbering the model artificially in regards to efficient retirement.

Q What is your concern with emergency energy costs in the model?

A In the Strategist model, the Companies have included an extremely expensive source of power purchases, emergency power. Typically, emergency power is regarded as exactly that, a resource of last resort when nothing else is available. The Companies have assumed that the cost of this energy is $16,600 per MWh[26] - or several hundred times as expensive as typical power sources.

This very high "emergency energy" price represents the costs incurred or reported by customers who suffer interruptions in service. In fact, there are numerous other lower cost measures that can be, and are, called upon before interrupting service. These include purchases from other companies, calls for demand response, and various emergency operating procedures. These do not appear to be adequately represented in the Companies' model.

In the model results, emergency energy represents only a fraction of the total system energy – anywhere from 80 MWh to 5,400 MWh per year, or something like 0.001% to 0.01% of total energy requirements in the LG&E/KU system – and yet the total costs of this energy reaches up to $90 million in some years and cases.

Q **These costs seem fairly small relative to the total operating and capital costs required to run the LG&E/KU system. Why are emergency generation costs a concern in this analysis?**

A Costs of $10-$90 million are small in comparison to the total production and new unit capital costs seen in this model on an annual basis (between 0.5% and 4%), but where these values become extremely important is in the difference between the Strategist runs, particularly for marginal units. It is unclear what threshold the Companies would require in order to determine if retirement or retrofit is the better option, and the difference between the NPVRR of the emergency power might, in some cases, exceed the cost difference between two scenario runs. For example, as indicated in Exhibit CRS-2 toWitness Schram's rebuttal testimony,

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[26] The $16,600 value remains constant throughout the study period, implying that the cost diminishes in real terms over the analysis period.

high emergency energy costs consistently favors the retrofit decision. Of note, using a $16,600/MWh charge rather than, for example, a cost of $1,000/MWh favors the retrofit of Mill Creek by $76 million, and Brown 1 & 2 by $23 million. I conclude that, even for these forward-planning exercises, it is quite critical to get this value correct and justified.

Q Are you able to give an example where the cost of emergency energy could tip the balance in this analysis?

A Yes. In the 2011 Air Compliance Plan (Exhibit CRS-1), the explanation next to the Cane Run 6 analysis explains that even though the NPVRR favors retrofit, the difference is quite small – only $8 million. The Companies explain (Section 4.2.5) that:

> If the Companies install controls on Cane Run 6 and the PVRR of a future expenditure not contemplated in this analysis exceeds $8 million, installing controls is not the least cost option. Because the possibility of this occurring is considered high, the Companies do not recommend installing environmental controls on Cane Run 6. Cane Run 6 will be retired when the air regulations take effect.

In contrast, under the section "Future Environmental Costs" in the Sensitivity (Section 2.3), the Companies explain that:

> Because more stringent NO_x emission reduction requirements in the future could require the construction of SCRs on some or all of these units, the Companies considered the cost of potential controls and whether these costs could be incurred without changing the Companies' current recommendation.

The Companies goes on to explain that the net value of Brown 1 & 2 in their analysis is $228 million, and the NPV of installing SCRs on these units is $195 million. The net difference, $33 million is, according the Companies, sufficiently large enough to justify the continued use of the units.

However, the NPVRR differences between scenarios due to the "emergency power cost" can quickly diminish the $33 million dollar value and feasibly change the results of the analysis. Indeed, witness Shram's rebuttal testimony would suggest that this value could be only $10 million net benefit if the cost of emergency energy is closer to $1000/MWh rather than $16,600/MWh.

Q What is your concern with the Companies' SO2 and NOx prices?

A In the concurrent 2011 IRP, the Companies show their forecast of SO_2 and NO_x prices. These prices start at $19 and $460/ton of pollutant, and drop to zero by 2014 – remaining at zero thereafter.

The Companies will have the opportunity to trade SO_2 and NO_X allowances within the state and outside the state to a limited extent under the CSAPR rule, and should therefore carefully evaluate the opportunities and opportunity costs associated with selling excess allowances through retirement or retrofit or purchasing allowances if plants are not retrofitted. The Companies should incorporate these costs into the Strategist model.

Q So why are the Companies' SO2 and NOx prices a concern?

A They are much lower than the prices predicted by the EPA. In its Regulatory Impact Assessment for the CSAPR rule, the EPA predicts that SO_2 prices in the Group 1 Trading Program (of which Kentucky is a member) at approximately $1000/ton in 2012 and $1,100 in 2014, while NO_x prices in the ozone season trading program (of which Kentucky is also a participant) will reach up to $1,500 in 2014 – a far cry from zero.

While I have not produced a prediction of SO_2 and NO_x trading prices after 2014, I believe it is incumbent on the Companies to carefully assess those costs and opportunities, as they have the potential to change the Companies' retire/retrofit calculus.

Q Do you also have a concern with the order of retirement stipulated by the Companies?

A Yes. I understand that the Companies evaluate the cost efficacy of maintaining their fleet on a unit-by-unit basis. Each time a unit is found to be non-economic in the retire/retrofit analysis, it is assumed to be retired in year 2016, as part of the base case. In this stepwise system, units which are analyzed early are compared to a "no retirements" or at least "few retirements" scenario, while units which are analyzed late are compared against a "many retirements" scenario. Each time a unit is retired, the remaining units, by virtue of being in a "closed" system, increase in capacity factor and therefore look marginally more economic.

By the time we examine the last units in this system, those units may look far more economic than if they were considered first.

Q What would you recommend the Companies do to rectify this problem?

A I understand that there is a legitimate question raised by retirement, in which remaining units may indeed have to make up some of the energy lost by retiring other units; therefore, I do not fundamentally object to this sort of test. However, I would suggest that the Companies should test each unit's cost effectiveness against the "no retirements" case, determine which units will be least cost effective *going forward* rather based on current operations and choose to retire the least economic units first. This sort of re-ordering of the analysis should happen in parallel with the evaluation of the emergency energy price, more mid-sized unit replacement (or large unit shares) options, and realistic connections between LG&E/KU and neighboring utilities. Given the immense dollar amounts at stake and minor expense of computer time and analysis labor, as well as the multi-decade length of the commitments involved, the company could feasibly find more optimal retirement/retrofit solutions.

I believe that these types of adjustments would make for a less noisy and more realistic solution by which to judge the merits of granting CPCN.

Q Have you corrected these Strategist problems for your testimony in this case?

A No. We have had to prioritize the efforts of this re-analysis given that we had a limited period of time in which to complete it. We chose to focus only on the most pressing concerns, described in the re-analysis sections.

Q Are there issues and errors in the company's use of Strategist beyond those that you've identified in this testimony?

A There may be other issues and errors. I have presented in this testimony all of the problems and concerns that I have identified at this point in time. That does not, of course, mean that there aren't other problems with the inputs or methodology that have gone unnoticed. System modeling is a complicated matter, and it should be done carefully and thoughtfully.

10. Conclusions

Q What are your conclusions?

A In my opinion, the company has used a series of input assumptions in their retire/ retrofit model that do not adequately reflect ratepayer risk. In addition, I have identified a number of concerns with the Companies' modeling framework and assumptions, but have not had the opportunity to assess how much these problems impact the retire/retrofit decision. Basing resource decisions on those assumptions and methodologies would burden the Companies' ratepayers with substantial and unnecessary costs and risks.

By correcting the company's natural gas price forecast, a move that the Companies appear to endorse as evidenced in their late-breaking "Supplemental Analysis" filed on September 14, 2011, the economic merit of retrofitting the Companies' coal-fired units diminishes significantly. A simple correction to the gas price should result in the decision to retire Brown 1 & 2, rather than expend additional dollars on retrofitting these units.

The Companies' assessment of the requirement for SCR requirements at Brown 1 & 2, Ghent 2, and Mill Creek 1 & 2 is inaccurate and understates the significant risk that these units will require rigorous NO_x controls to comply with both current and pending ozone rules. Even accepting the company's gas price forecast, the risk of SCR at Brown 1 & 2 should result in the choice to retire, rather than retrofit these units. When the mid-range gas price forecast is utilized and under the circumstance that SCR is required, Brown 1 & 2 are clearly non-economic and pose a marked risk to ratepayers. The Mill Creek 1 & 2 units remain marginally economic, but would certainly be considered high risk under this circumstance and that is *only* if all the other erroneous assumptions and methodologies are ignored.

Finally, I believe that the lack of a CO_2 price (or a range of CO_2 forecasts) in the Companies' model inappropriately exposes the Companies and their ratepayers to substantial costs for carbon regulatory risk. Indeed, applying a mid-range CO_2 price to the forecast results in the marked reduction in cost-effectiveness of all of the Companies' coal units. Applying both the CO_2 price and the adjusted natural gas price makes much of the KU/LGE fleet appear non-economic.

Q What are your recommendations to the Commission?

A My recommendation is two-fold:

- First, under most reasonable assumptions, retrofitting and operating Brown Units 1 & 2 is anywhere from marginal to non-economic, relative to replacement with natural gas. Therefore, I recommend the Commission deny CPCN for these units. It is unlikely that a re-analysis of the risks to Brown Units 1 & 2 would result in a dramatically different outcome for these units.

- Second, a corrected gas price and mid-level CO_2 price appears to render much of the KU/LG&E fleet non-economic. However, in absence of more information about replacement capacity availability and transmission costs and availability, a specific course of action for these other units cannot be recommended at this time. Instead, it is incumbent on the Companies to assess these costs and risks comprehensively prior to requesting a CPCN.

The net impact of these considerations is that I recommend that, in this docket, the Commission deny the requested CPCNs.

Jeremy I. Fisher, PhD

Curriculum Vitae

Synapse Energy Economics	(617) 453-7045 (Direct)
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EMPLOYMENT

Scientist **2007-present**
Synapse Energy Economics

- Model and evaluation of avoided emissions from energy efficiency and renewable energy (Utah State, *California Energy Commission*, US EPA, *State of Connecticut*),
- Evaluation of heath, water, and social co-benefits of energy efficiency and renewable energy (Utah State, Civil Society Institute)
- Develop analysis of water consumption and withdrawals from electricity sector (Stockholm Environment Institute, Union of Concerned Scientists)
- Estimate of compliance costs for environmental regulations (Western Grid Group)
- Development of alternate energy plans for municipalities, states, and regions (Sierra Club Los Angeles, NRDC Michigan, Western Resource Advocates Nevada)
- Price impacts of carbon policy on electricity generators and consumers (NARUC, NASUCA, APPA, NRECA)
- Facilitate and provide energy sector modeling for stakeholder-driven carbon mitigation program in Alaska (Center for Climate Strategies)
- Estimate of greenhouse gas emissions reductions from energy efficiency, agricultural and forestry offsets for all US states (Environmental Defense Fund)
- Economic cost of climate change on energy sector in US and Florida (EDF, NRDC)
- Estimate full costs of nuclear waste decommissioning in West Valley site

Postdoctoral Research Scientist **2006-2007**
Tulane University, Department of Ecology and Evolutionary Biology
University of New Hampshire, Institute for the Study of Earth, Oceans, and Space

- Predicted forest mortality from wind damage using satellite data and ecosystem model
- Analyzed Gulf Coast ecosystem impacts of Hurricane Katrina
- Wrote and organized team synthesis review on causes of natural rainforest loss in the Amazon basin
- Redeveloped ecosystem model to explore carbon ramifications of long-term Amazon disturbance

Visiting Fellow **2007-2008**
Brown University, Watson Institute for International Studies

- Designed remote sensing study to examine migratory bird response to climate variability in Middle-East

Research Assistant **2001-2006**
Brown University, Department of Geological Sciences

- Used satellite data to track influence of local and global climate patterns on temperate forest seasonality
- Worked with West African collaborators to determine land-use impact on landscape degradation
- Investigated coastal power plant effluent through multi-temporal satellite data

Remote Sensing Analyst **2005-2006**
Consultant for Geosyntec. in Acton, Massachusetts

- Mapped estuary from hyperspectral remote sensing data to determine impact of engineered tidal system
- Developed suite of algorithms to correct optical and sensor error in hyperspectral dataset

Remote Sensing Specialist **2000**
3Di, LLC. Remote Sensing Department. Easton, Maryland

Research Assistant **1999-2001**
University of Maryland, Laboratory for Global Remote Sensing Studies
- Developed GIS tools for monitoring global ecological trends
- Created thermal model of continental ice properties from microwave satellite data

EDUCATION

Ph.D. Geological Sciences	**2006**	Brown University, Providence, Rhode Island
M.Sc. Geological Sciences	**2003**	Brown University, Providence Rhode Island
B.S. Geography	**2001**	University of Maryland, College Park, Maryland
B.S. Geology *(honors)*	**2001**	University of Maryland, College Park, Maryland

WHITE PAPERS

Fisher, J.I. , R. Wilson, N. Hughes, M. Wittenstein, B. Biewald. 2011. Benefits of Beyond BAU. White paper *for* Civil Society Institute. Synapse Energy Economics.

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Bruce E. Biewald **Fisher, J.I.** C James. L. Johnston, D. Schlissel. R. Wilson. 2009. Energy Future: A Green Energy Alternative for Michigan. White paper *for* Sierra Club. Synapse Energy Economics.

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Fisher, J.I., B. Biewald. **2007** Electricity Sector. *in* E.A. Stanton and F. Ackerman. *Florida and Climate Change: The Costs of Inaction*. Tufts University.

PEER-REVIEWED PUBLICATIONS

J. T. Morisette, A. D. Richardson, A. K. Knapp, **J.I. Fisher** , E. Graham, J. Abatzoglou, B.E. Wilson, D. D. Breshears , G. M. Henebry, J. M. Hanes and L. Liang. **2009**. Tracking the rhythm of the seasons in the face of global change: Challenges and opportunities for phenological research in the 21st Century. In Press at *Frontiers in Ecology*.

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Fisher, J.I. and S.J. Goetz. **2001** Considerations in the use of high spatial resolution imagery: an applications research assessment. *American Society for Photogrammetry and Remote Sensing (ASPRS) Conference Proceedings*, St. Louis, MO.

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Fisher, J.I. and J.F. Mustard. High spatial resolution sea surface climatology from Landsat thermal infrared data. *Ecological Society of America Conference.* Savannah, GA. August, 2003.

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Fisher, J.I. Climate Change, Water, and Risk in Electricity Planning. National Association of Regulatory Utility Commissioners (NARUC), Portland, OR. July 22, 2008.

Fisher, J.I. E. Hausman, and C. James. Emissions Behavior in the Northeast from the EPA Acid Rain Monitoring Dataset. Northeast States for Coordinated Air Use Management (NESCAUM), Boston, MA. January 30, 2008.

Fisher, J.I. J.F. Mustard, and M. Vadeboncoeur. Climate and phenological variability from satellite data. Ecology and Evolutionary Biology, Tulane University. March 24, 2006.

Fisher, J.I., J.F. Mustard, and M. Vadeboncoeur. Anthropogenic and climatic influences on green leaf phenology: new observations from Landsat data. Ecosystems Center at the Marine Biological Laboratory. Woods Hole, MA. Seminar, September 27, 2005.

Fisher, J.I. and J.F. Mustard. High resolution phenological modeling in Southern New England. Woods Hole Research Center. Woods Hole, MA. Seminar, March 16, 2005.

TEACHING

Teaching Assistant	**2005**	Global Environmental Remote Sensing, Brown University
Teaching Assistant	**2002 & 2004**	Estuarine Oceanography, Brown University
Laboratory Instructor	**2002**	Introduction to Geology, University of Maryland

FELLOWSHIPS

2007 Visiting Fellow, Watson Institute for International Studies, Brown University

2003 Fellow, National Science Foundation East Asia Summer Institute (EASI)
2003 Fellow, Henry Luce Foundation at the Watson Institute for International Studies, Brown University

UNIVERSITY SERVICE

Representative	**2005-2006**	Honorary Degrees Committee, Brown University
Representative	**2004-2006**	Graduate Student Council, Brown University

PROFESSIONAL ASSOCIATIONS

American Geophysical Union; Geological Society of America; Ecological Society of America; Sigma Xi

Net Present Value Revenue Requirement (NPVRR) of Installing Controls vs. Retiring and Replacing Capacity (Million 2010$)

Nominal Dollar Analysis & Wood Mackenzie Gas Prices - October 31, 2011

Original KU/LG&E Analysis

KU / LG&E Assumptions — Original (Box 1)	
CPCN Results	
Tyrone 3	-13
Green River 3	-80
Brown 3	601
Cane Run 4	-88
Cane Run 6	8
Brown 1-2	228
Cane Run 5	-58
Ghent 3	914
Ghent 1	794
Green River 4	-110
Mill Creek 4	859
Trimble County 1	993
Ghent 4	1,155
Mill Creek 3	756
Ghent 2	1,139
Mill Creek 1-2	1,022

KU / LG&E Assumptions — Original, Formula Corrected (Box 2)	
CPCN Results, Landfill Year Corrected	
Tyrone 3	-13
Green River 3	-80
Brown 3	603
Cane Run 4	-87
Cane Run 6	11
Brown 1-2	230
Cane Run 5	-57
Ghent 3	921
Ghent 1	800
Green River 4	-110
Mill Creek 4	859
Trimble County 1	996
Ghent 4	1,161
Mill Creek 3	756
Ghent 2	1,146
Mill Creek 1-2	1,022

Key	
If NPVRR relative to no retirement scenario	
≥ $40 M, retrofit	100
< $40 M & ≥ $0 M, high risk retrofit	20
< $0 M, retire	-80

*Wood Mackenzie Gas and/or Synapse Mid CO2, Nominal

Synapse Re-Analysis — Single Variable Correction

Synapse Re-Analysis — A (Box 3)	
Nominal Wood Mackenzie Gas Price*	
Tyrone 3	-59
Green River 3	-66
Brown 3	368
Cane Run 4	-240
Cane Run 6	-67
Brown 1-2	49
Cane Run 5	-193
Ghent 3	529
Ghent 1	430
Green River 4	-130
Mill Creek 4	484
Trimble County 1	654
Ghent 4	727
Mill Creek 3	423
Ghent 2	728
Mill Creek 1-2	530

Synapse Re-Analysis — B (Box 4)	
SCR at Brown 1 & 2, Ghent 2, and Mill Creek 1 & 2	
Tyrone 3	-13
Green River 3	-80
Brown 3	603
Cane Run 4	-87
Cane Run 6	11
Brown 1-2 (+SCR)	34
Cane Run 5	-57
Ghent 3	921
Ghent 1	800
Green River 4	-110
Mill Creek 4	859
Trimble County 1	996
Ghent 4	1,161
Mill Creek 3	756
Ghent 2 (+SCR)	858
Mill Creek 1-2 (+SCR)	762

Synapse Re-Analysis — C (Box 5)	
Synapse Mid CO_2 Price*	
Tyrone 3	-87
Green River 3	-74
Brown 3	-70
Cane Run 4	-450
Cane Run 6	-384
Brown 1-2	-157
Cane Run 5	-329
Ghent 3	58
Ghent 1	-4
Green River 4	-234
Mill Creek 4	162
Trimble County 1	387
Ghent 4	422
Mill Creek 3	177
Ghent 2	438
Mill Creek 1-2	-20

Synapse Re-Analysis — Multiple Variable Correction

Synapse Re-Analysis — A + B (Box 6)	
Nominal Wood Mackenize Gas Price* + SCRs	
Tyrone 3	-59
Green River 3	-66
Brown 3	368
Cane Run 4	-240
Cane Run 6	-67
Brown 1-2 (+SCR)	-146
Cane Run 5	-193
Ghent 3	529
Ghent 1	430
Green River 4	-130
Mill Creek 4	484
Trimble County 1	654
Ghent 4	727
Mill Creek 3	423
Ghent 2 (+SCR)	441
Mill Creek 1-2 (+SCR)	270

Synapse Re-Analysis — A + C (Box 7)	
Nominal WoodMac Gas + Synapse Mid CO_2*	
Tyrone 3	-118
Green River 3	-129
Brown 3	-475
Cane Run 4	-594
Cane Run 6	-621
Brown 1-2	-324
Cane Run 5	-386
Ghent 3	-347
Ghent 1	-357
Green River 4	-336
Mill Creek 4	-157
Trimble County 1	75
Ghent 4	96
Mill Creek 3	-121
Ghent 2	99
Mill Creek 1-2	-563

Synapse Re-Analysis — A + B + C (Box 8)	
Nominal AESC Gas + Synapse Mid CO_2* + SCRs	
Tyrone 3	-118
Green River 3	-129
Brown 3	-475
Cane Run 4	-594
Cane Run 6	-621
Brown 1-2 (+SCR)	-519
Cane Run 5	-386
Ghent 3	-347
Ghent 1	-357
Green River 4	-336
Mill Creek 4	-157
Trimble County 1	75
Ghent 4	96
Mill Creek 3	-121
Ghent 2 (+SCR)	-189
Mill Creek 1-2 (+SCR)	-824

Synapse
Energy Economics, Inc.

2011 Carbon Dioxide Price Forecast

February 11, 2011

(Amended August 10, 2011)

AUTHORS
Lucy Johnston, Ezra Hausman,
Bruce Biewald, Rachel Wilson,
David White

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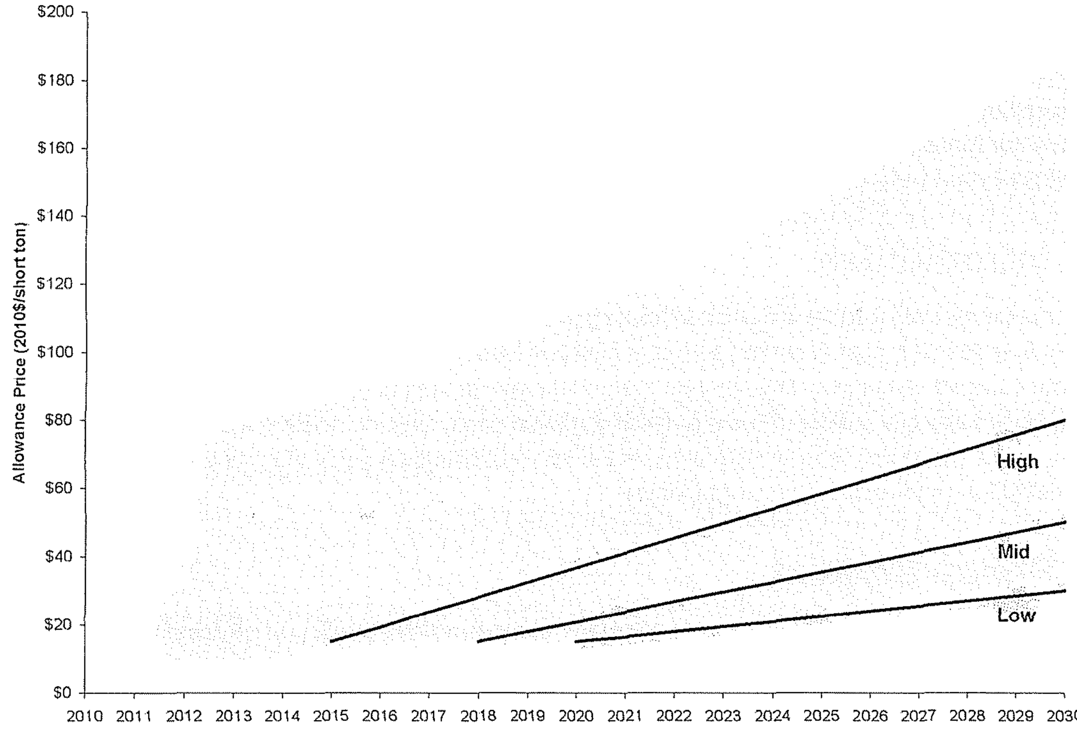
Table of Contents

1. Executive Summary

Synapse has prepared 2011 CO_2 price projections for use in Integrated Resource Planning (IRP) and other electricity resource planning analyses. Our projections of prices associated with carbon dioxide emissions reflect a reasonable range of expectations regarding the likelihood and the magnitude of costs for greenhouse gas emissions. Our high bound on our CO_2 Price Forecast starts at $15/ton in 2015, and rises to approximately $80/ton in 2030. This High Forecast represents a $43/ton levelized price over the period 2015-2030. The low boundary on the Synapse CO_2 price forecast starts at $15/ton in 2020, and increases to approximately $30/ton in 2030. This represents a $13/ton levelized price over the period 2020-2030. Synapse also has prepared a Mid CO_2 Price Forecast that starts a bit more slowly, but close to the low case, at $15/ton in 2018, but then climbs to $50/ton by 2030. The levelized cost of this mid CO_2 price forecast is $26/ton. All annual allowance price and levelized values are given in 2010 dollars per short ton of carbon dioxide.[1] Our forecast is presented below, in Figure ES-1. The shaded region shows a range of allowance prices forecasted by various analyses of legislative cap-and-trade proposals. Further details on these proposals are shown in later Figures.

Figure ES-1: Synapse price forecast



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[1] All values in the Synapse Forecast are presented in 2010 dollars. Results from EIA and EPA modeling analyses were converted to 2010 dollars using price deflators taken from the US Bureau of Economic Analysis, and available at: http://www.bea.gov/national/nipaweb/SelectTable.asp Because data were not available for 2010 in its entirety, values used for conversion were taken from Q3 of each year. Consistent with EIA and EPA modeling analyses, a 5% real discount rate was used in all levelization calculations.

The future of climate change policy is unclear. While climate legislation was considered in the last Congress, and passed the House, it did not pass the Senate; currently, there are a range of actions that could be taken by federal entities in the legislative, executive and judicial branches of government, as well as by states individually and in regional organizations that will affect the competitiveness of resources with greenhouse gas emissions (these are described in more detail in the body of this report). The lack of clarity regarding the future of climate change policy in the United States presents a challenge, but is not justification for assuming there will be no cost associated with greenhouse gases, no effect on the competitiveness of resources based on their greenhouse gas emissions. Though we cannot predict specific policies that will develop between now and 2030, the end of our forecast period, we believe that current and emerging state, regional, and federal policies are all indications that greenhouse gas emissions will not be without cost impact on the emitter over the course of any investment in long-term resources. Indeed, it would be imprudent to make resource decisions today based upon an assumption that carbon emissions will be unregulated, or priced at zero, in the future.

The Synapse projections represent a range of possible future costs, recommended price trajectories, that are useful for testing range-sensitivity of various investment possibilities in resource planning in the electric sector. The projection does not represent a prediction of specific *future price trajectories; there will be variability and volatility in prices following supply and demand* dynamics, as there is with other cost drivers. We intend and anticipate that the CO_2 price projections presented here will be useful for planning in the face of uncertainty.

While reasonable people may argue about the ultimate timing and details of any policy, about the likelihood of various forms of federal policy, and about the costs of specific technologies, we believe our forecast represents a valuable tool for use in resource planning and selection and in investment decisions in the electric sector.

2. Introduction

Over the next several years the economics of power generation will change in a manner that makes sources with high greenhouse gas emissions less competitive relative to those with lower greenhouse gas emissions. This change in the competitiveness of resources will result from interactions among a variety of factors (including state policy actions, federal agency regulations, federal court decisions, federal legislative initiatives, technological innovation, and presidential administrations) not due to any single factor.

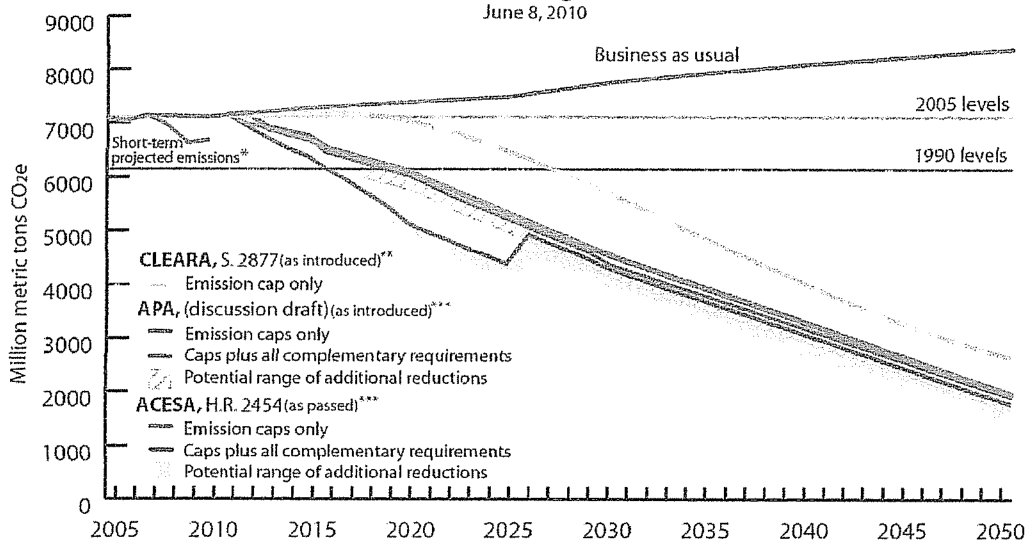
3. Policy Context

In the past few years, Congress has been a major focus for climate policy. Congress has considered enacting legislation that would reduce greenhouse gas emissions through a federal cap on greenhouse gas emissions and trading emissions allowances, or through other means. Legislative proposals and the President Obama's initiatives aim to reduce greenhouse gas emissions by approximately 80% from current levels by 2050.

Figure 1, below, shows the emissions reductions trajectories from recent legislative proposals (Waxman-Markey HR 2454, Kerry-Lieberman APA 2010, and Cantwell-Collins S. 2877).

Figure 1. Net Estimates of Emissions Reductions Under Pollution Reduction Proposals in the 111th U.S. Congress, 2005-2050

June 8, 2010



WORLD RESOURCES INSTITUTE

For a full discussion of underlying methodology, assumptions and references, please see http://www.wri.org/usclimatetargets.
*"Business as usual" emission projections are from EPA's reference case for its analysis of the Waxman-Markey bill. "Short-term projected emissions" represent EIA's most recent estimates of emissions for 2008-2010.
** The CLEARA sets economy-wide reduction targets beginning with a 20 percent reduction from 2005 levels by 2020. However, additional action by Congress would be required before these targets could be met. Reduction estimates do not include emissions increases above the cap that could occur if the safety-valve is triggered.
*** The APA and the ACESA allow offsets from emission reduction activities outside the cap to be used for a portion of compliance. If these offsets are not real, additional, verifiable and permanent, net emissions reductions would decrease proportionately

2

Despite passage of comprehensive climate legislation in the House in the 111th Congress, the Senate ultimately did not take up climate legislation in that session. On the other hand, the Senate did consider -- but did not pass – legislation that would have restricted the Environmental Protection Agency's ability to regulate greenhouse gases.

As the 112th Congress opens, prospects for legislation establishing an economy-wide emissions cap seem dim, and legislators seem instead likely to focus on policies that would foster technology innovation, and a possible multi-regulation approach to energy issues. The 112th Congress is opening with simultaneous promises to use Congressional authority to prevent or delay EPA's ability to issue regulations concerning greenhouse gas emissions, and increasing interest in developing renewable energy standards or clean energy standards. Congress is unlikely to take up an economy-wide cap and trade program in its new session, instead, legislators are likely to focus on policies that promote technological innovation.

In fact, Congressional action is only one avenue in an increasingly dynamic and complex web of activities that could result in internalizing a portion of the costs associated with emissions of greenhouse gases from the electric sector. As Congress wrestles with the issue, the states, the federal courts, and federal agencies also grapple with the complex issues associated with climate change. Many efforts are proceeding simultaneously.

The U.S. Environmental Protection Agency (EPA) intends to mandate emissions reductions following the Supreme Court's determination that the harms associated with climate change are serious and well-recognized, that greenhouse gases fit within the Clean Air Act's definition of "air pollutant", and that the EPA has the authority to regulate greenhouse gases.[2] As a first step, the EPA issued a finding that greenhouse gases endanger public health and welfare. The EPA has also developed regulations to limit any greenhouse gas emission permitting requirements to the largest industrial sources, as well as regulations that boost automobile and truck fuel efficiency and contain the first-ever greenhouse gas tailpipe standards for vehicles. On August 12, 2010, EPA proposed two rules to ensure that businesses planning to build new, large facilities or make major expansions to existing ones obtain New Source Review Prevention of Significant Deterioration (PSD) permits that address greenhouse gases (GHG). These rules became effective in early January 2011. EPA announced December 23, 2010 that it will issue greenhouse gas performance standards for new and modified electric generating units under section 111(b) of the Clean Air Act, and for existing electric generating units under section 111(d) with final regulations promulgated in May 2012 and December 2012, respectively.[3]

The states – individually and coordinating within regions - are leading the nation's policies to respond to the threat of climate change. In fact, several states, unwilling to postpone and wait for federal action, are pursuing policies specifically because of the lack of federal legislation.

States continue to be the innovative laboratories for climate policy, and they are pursuing a wide variety of policies across the country.

- Forty-three states have a greenhouse gas inventory,
- Forty-one states have a greenhouse gas registry,
- Thirty-six states have completed a climate action plan or have one in progress,
- Twenty-two states have greenhouse gas emissions targets,
- Eleven states have an electric sector cap and allowance trading,
- Five states have emissions performance standards.
- Twenty-one states are participating in the operation or development of regional emissions cap and allowance trading programs, with an additional nine states as official observers in those processes.
- Only Nebraska, North Dakota, and the District of Columbia appear not to be taking specific climate-related policy initiatives at this time.
- In general, states are also where the nitty-gritty decisions will be made about investments in new or existing power plants.

The map below shows states with emission targets and those participating in, or observing, regional climate initiatives as of January 2011. States that have adopted emissions targets and/or that are participating actively in regional climate initiatives comprise 44.4% of US electrical generation, 48.3% of retail electricity sales, and 58.1% of U.S. population. The observer states add

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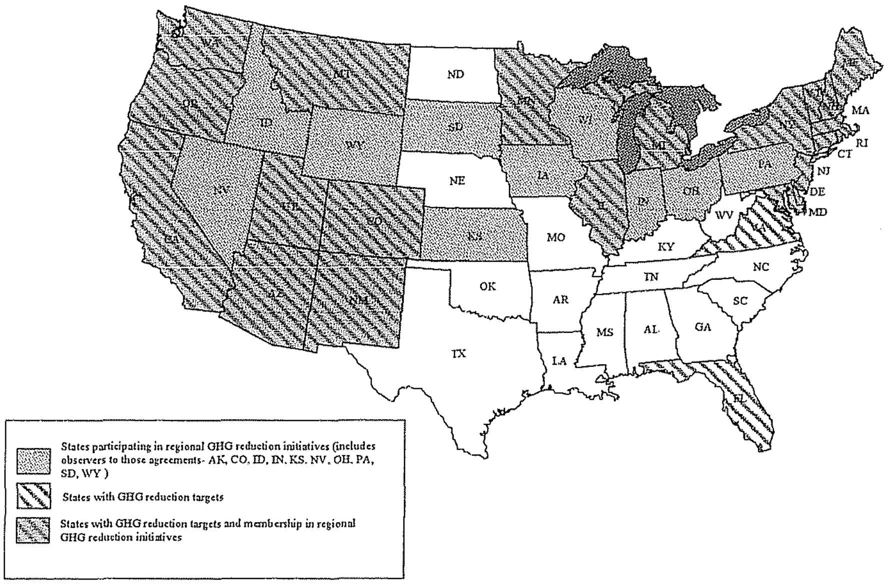
[2] Information on EPA's plans and regulations available from EPA website on climate change regulatory initiatives at http://www.epa.gov/climatechange/initiatives/index.html

[3] U.S. EPA, EPA to Set Modest Pace for Greenhouse Gas Standards, Press Release December 23, 2010. And U.S. EPA, Settlement Agreements to Address Greenhouse Gas Emissions from Electric Generating Units and Refineries - Fact Sheet, December 23, 2010. Available at http://www.epa.gov/airquality/pdfs/settlementfactsheet.pdf

an additional 17.3% of electrical generation, 16.1 % of retail electricity sales, and 14.5% of the U.S. population.

Figure 2: States in regional climate initiatives and/or with greenhouse gas targets



Source. Pew Center on Global Climate Change

Three regions in the country have developed, or are developing greenhouse gas caps and allowance trading:

Regional Greenhouse Gas Initiative: The Regional Greenhouse Gas Initiative (RGGI) is an effort of ten Northeast and Mid-Atlantic states to limit greenhouse gas emissions and is the first market-based CO_2 emissions reduction program in the United States. Participating states have agreed to a mandatory cap on CO_2 emissions from the power sector with the goal of achieving a ten percent reduction in these emissions from levels at the start of the program by 2018.[4] This is the first mandatory carbon trading program in the nation.

Western Climate Initiative: In 2007, Governors of five western states signed an agreement establishing the Western Climate Initiative (WCI), a joint effort to reduce greenhouse gas (GHG) emissions and address climate change.[5] Subsequently, two more states and four Canadian Provinces also joined the effort.[6] Fourteen states and provinces also are official observers of the process.[7] WCI members signed a Memorandum of Understanding agreeing to jointly set a regional emissions target and establish a market-based system—such as a cap-and-trade program covering

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[4] The ten states are: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. Information on the RGGI program, including history, important documents, and auction results is available on the RGGI Inc website at www.rggi.org

[5] The five states are Arizona, California, New Mexico, Oregon and Washington.

[6] Utah, Montana, British Columbia, Manitoba, Ontario and Quebec.

[7] Alaska, Colorado, Idaho, Kansas, Nevada, and Wyoming, as well as the provinces of Nova Scotia and Saskatchewan and the Mexican states of Baja California, Chihuahua, Coahuila, Nuevo Leon, Sonora, and Tamaulipas.

multiple economic sectors—to aid in meeting this target. The WCI regional, economy-wide greenhouse gas emissions target is 15 percent below 2005 levels by 2020, or approximately 33 percent below business-as-usual levels. The WCI Partners released the Design for the WCI Regional Program in 2010.[8]

Midwest Greenhouse Gas Reduction Accord: In 2007, six states and one Canadian province established the Midwest Greenhouse Gas Reduction Accord (MGGRA).[9] Three additional states are official observers.[10] The members agree to establish regional greenhouse gas reduction targets, including a long-term target of 60 to 80 percent below current emissions levels, and develop a multi-sector cap-and-trade system to help meet the targets. The MGGRA Advisory Group presented final recommendations in May 2010.[11]

The Federal Courts have allowed common law nuisance actions to go forward against some of the nation's largest owners and operators of fossil fueled facilities. In those actions, plaintiffs successfully stated a cause of action for harm suffered as a result of defendants' carbon intensive activities that contributed to climate change. The Supreme Court is due to take up legality of "nuisance" lawsuits over greenhouse gas emissions in 2012. If nuisance lawsuits are allowed to go forward, the threat of climate change lawsuits could spur congressional action.

It is not likely that all of these initiatives will move forward and result in a cost to emitting greenhouse gases. It is also not likely that none of these initiatives or similar initiatives will move forward. Any of these will happen in the context of implementing other policies that, while not focusing directly on greenhouse gas emissions (e.g. renewable standards, efficiency standards, investment in new technologies etc.) will reduce greenhouse gas emissions.

In the absence of a comprehensive federal policy, efforts to address the climate issues will persist, albeit in a variety of forums. The multiple threats of EPA regulation, litigation (nuisance and plant by plant), and diverse state policies could very well create a strong demand for coordinated federal legislation. However, it is clear that the absence of federal legislation has not brought efforts to formulate policies addressing greenhouse gas emissions to a halt, and it is equally clear that these policies will affect the costs of operating resources with high levels of greenhouse gas emissions. Regulation of greenhouse gases will increase the cost of producing electricity from power sources that emit greenhouse gases, reflecting either the direct cost of reducing emissions or the cost of purchasing emissions allowances. Though it is certain that emission-related costs will increase, the nature, magnitude and timing of the cost increases are uncertain and thus introduce financial risk into decisions to invest in long-lived capital-intensive resources that use carbon-based fuels.

Meanwhile, negotiations for international coordination on initiatives to mitigate and adapt to climate change are on-going. Most recently, the 2009 Copenhagen Accord called on developed nations to submit quantified greenhouse gas emission reduction targets for 2020, and for developing nations to submit "nationally appropriate mitigation actions." The United States has said it will reduce

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[8] This summary is based on information available from Pew Center on Global Climate Change, www.pewclimate.org; and also from the WCI website, www.westernclimateinitiative.org.

[9] The states are Illinois, Iowa, Kansas, Michigan, Minnesota, and Wisconsin, as well as the Premier of the Canadian Province of Manitoba.

[10] Observers are Indiana, Ohio, and South Dakota.

[11] This summary is based on information available from Pew Center on Global Climate Change, www.pewclimate.org; and also from the MGGRA website, www.midwesternaccord.org

CLERK'S CERTIFICATE OF SERVICE

This is to certify that a true and correct copy of the foregoing ORDER was sent this _____ day of _____________, 2011, via U.S. mail to the following:

Edward George Zuger III, Esq.
Zuger Law Office
P.O. Box 728
Corbin, Kentucky 40702

Hon. Andrea Issod
Hon. Nathaniel Shoaff
Sierra Club Environmental Law Program
85 Second St., 2nd Floor
San Francisco, CA 94105
Counsel for Petitioners

Hon. Mary Stephens
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Energy & Environment Cabinet
200 Fair Oaks Lane, Fourth Floor
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Counsel for Respondent Energy and Environment Cabinet

Hon. Jack Bender
Hon. R. Clay Larkin
Greenebaum Doll McDonald PLLC
300 West Vine Street, Ste 1100
Lexington, KY 40507
Counsel for Respondent Louisville Gas & Electric Company

____
Clerk, Trimble Circuit Court

greenhouse gas emissions in the range of 17% below 2005 levels by 2020, which is a target consistent with anticipated climate and energy legislation.[12]

4. Elements in a price projection

A. Difficulty of price projection under uncertainty

Though the need for a comprehensive effort to reduce greenhouse gas emissions seems clear, the particular set of policies that will be adopted to bring about a low carbon economy are unknown. It is also likely that some policies will focus on adaptation rather than emissions reduction. Nevertheless, while state and federal policy-makers continue to struggle with the details and political challenges of such an effort, the need for a reliable and cost-effective electric sector does not diminish. Regardless of what the policy or policies ultimately look like, it is certain that any policy requiring, or leading to, greenhouse gas emission reductions will mean that there is a cost associated with emitting greenhouse gases over at least some portion of the life of a long-lived resource. Despite policy uncertainty, it is important to incorporate some reasonable consideration of a range of potential costs into long-term investment planning in the electric sector.

There are several types of information that are useful to consult in developing a reasonable *forecast of the cost of carbon emissions for decision-making in the electric sector. Though none of* this information can predict future costs, it is useful as a point of reference in developing a reasonable forecast. Information includes analyses of compliance costs under various federal cap and trade proposals, costs of low carbon technologies, projections of compliance costs under mandatory emission reduction programs other than cap and trade. For this forecast, we have focused primarily on analyses of federal cap and trade proposals since they present a well analyzed and comprehensive exploration of the possible costs associated with carbon dioxide emissions. But we have also taken into account other sources of information.

A large number of modeling analyses have been undertaken to evaluate the CO_2 allowance prices that would result from the major climate change bills introduced in Congress over the past several years. Though it is not certain that a federal cap and allowance trading program will ultimately be what is adopted, analyses of the various proposals to date are one of the sources of the most comprehensive estimates of costs associated with greenhouse gas emissions under a variety of regulatory scenarios. These estimates can be useful sources of information. It is not possible to compare the results of all of these analyses directly because the specific models and the key assumptions vary. Further, it is not certain that a federal cap and trade program will be the form that climate policy in the U.S. takes. While consistent federal rules would be the most efficient mechanism for climate policy, the costs are associated with emissions limits and other policy details, not with the source of the rules. Accordingly, the results of these analyses provide important insights into the ranges of possible future CO_2 allowance prices under a range of potential scenarios.

[12] Information is available at http://www.pewclime.org/copenhagen-accord

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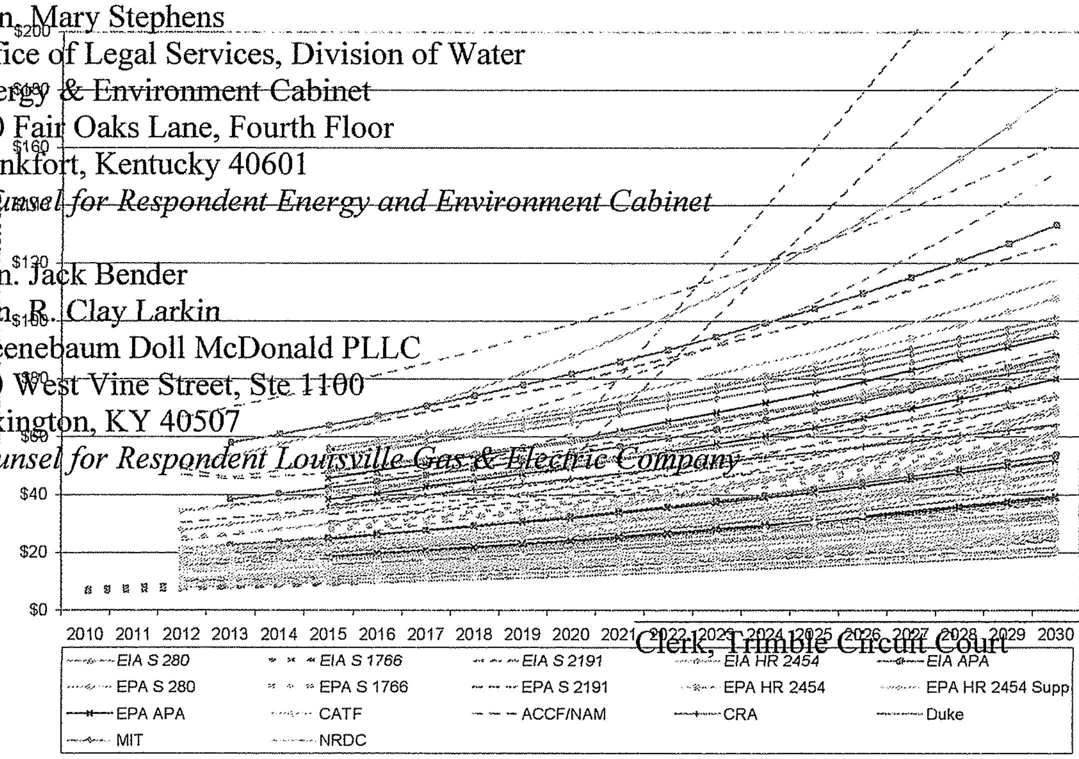
Clerk, Trimble Circuit Court

B. Analyses of compliance costs- and conclusions on effects of factors

The results of the dozens of analyses over the past several years show that there are a number of factors that affect projections of allowance prices under federal greenhouse gas regulation. Some of these derive from the details of policy design, some of them pertain to the outlook for the context in which a policy would be implemented. These include: the base case emissions forecast; the reduction targets in each proposal; whether complementary policies such as aggressive investments in energy efficiency and renewable energy are implemented, independent of the emissions allowance market; the policy implementation timeline; program flexibility regarding emissions offsets (perhaps international) and allowance banking; assumptions about technological progress; the presence or absence of a "safety valve" price; and emissions co-benefits.

The graph below shows the results of all the scenarios from multiple analyses in the past several years. The studies that are incorporated into this graph are identified in Appendix A.

Figure 3: Greenhouse gas allowance price projections based on analyses of federal legislative proposals



The results of these same analyses are represented in Figure 4, below, as ranges of levelized costs.

COMMONWEALTH OF KENTUCKY
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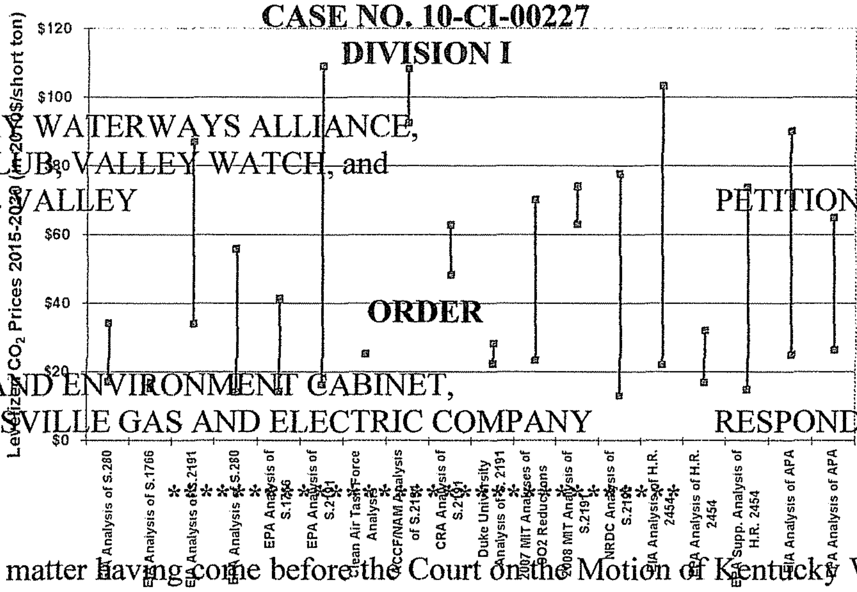
DIVISION I

Figure 4: Greenhouse gas allowance price projections from analyses of federal legislative proposals - levelized



KENTUCKY WATERWAYS ALLIANCE,
SIERRA CLUB, VALLEY WATCH, and
SAVE THE VALLEY PETITIONERS,

v.

ORDER

ENERGY AND ENVIRONMENT CABINET,
AND LOUISVILLE GAS AND ELECTRIC COMPANY RESPONDENTS.

* *

We have looked ("in more detail") at the EIA and EPA analyses of the three major legislative proposals in the 111th Congress. The results of these analyses span a similar range to earlier studies. The chart below shows the forecasted allowance prices in all of the scenarios of those analyses.

This matter having come before the Court on the Motion of Kentucky Waterways Alliance, *et al.* ("Petitioners"), to transfer this matter to Franklin County Circuit Court pursuant to KRS 452.105, and the Court having reviewed the pleadings and briefs of the parties, having heard arguments of counsel, and being otherwise sufficiently advised, it is hereby ORDERED as follows:

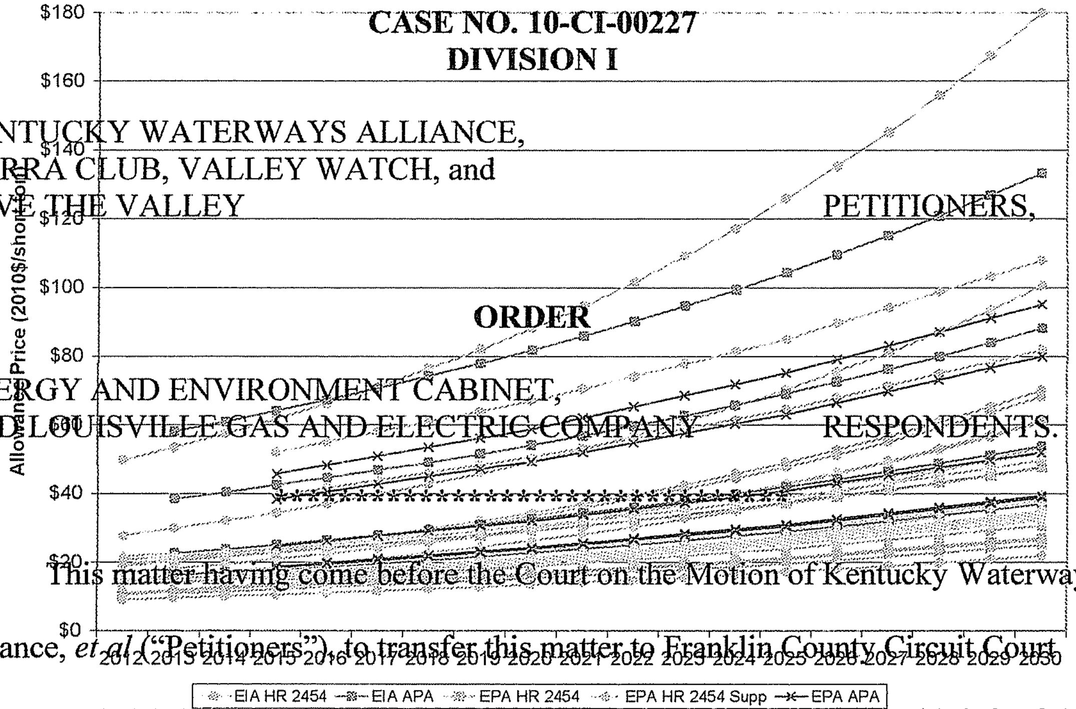
1. Petitioners' Motion to Transfer is GRANTED.
2. The Trimble County Circuit Court Clerk shall hereby transfer C.A. 10-CI-00227 to the Franklin County Circuit Court Clerk.

So ordered, this _____ day of ___________, 2011.

____
SPECIAL JUDGE, TRIMBLE CIRCUIT COURT

COMMONWEALTH OF KENTUCKY
12TH JUDICIAL CIRCUIT
TRIMBLE CIRCUIT COURT
CASE NO. 10-CI-00227
DIVISION I

Figure 5: Greenhouse gas allowa... and APA 2010



KENTUCKY WATERWAYS ALLIANCE,
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These values are shown as levelized prices for the time period 2015 to 2030 in Figure 6 below.

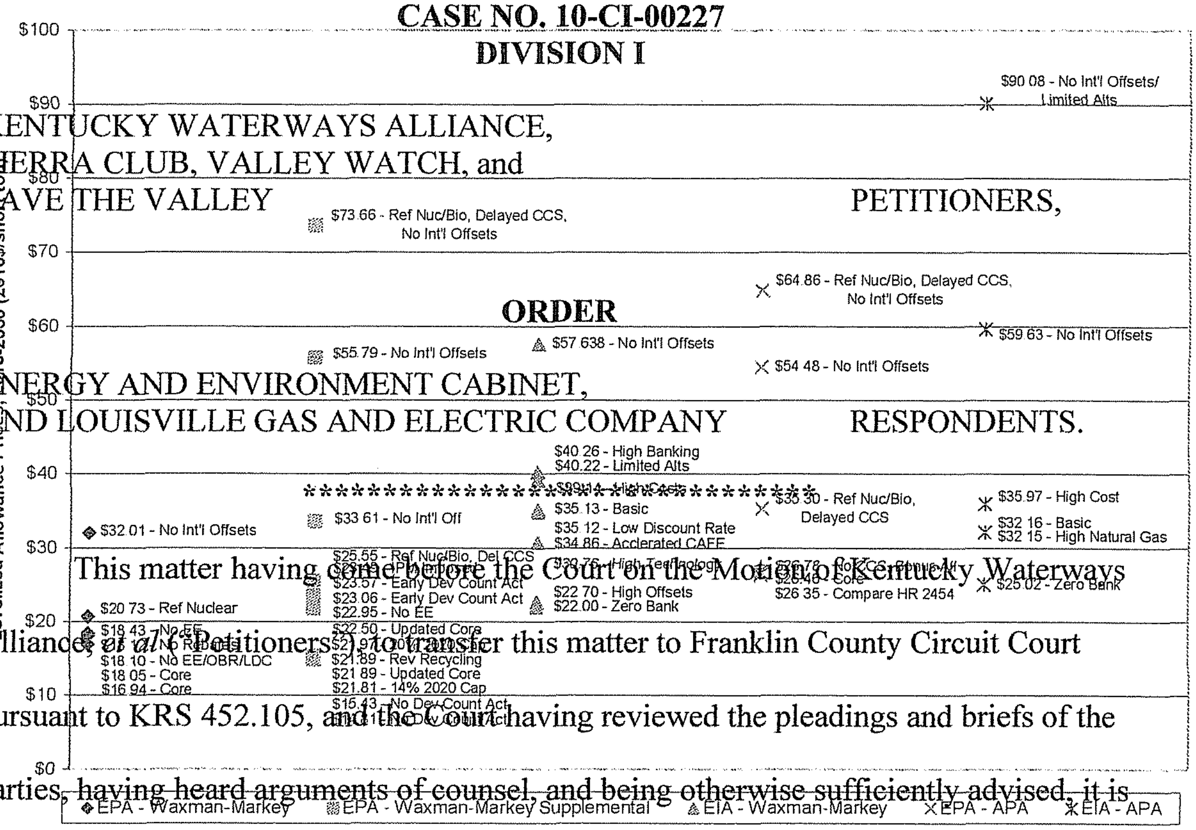
1. Petitioners' Motion to Transfer is GRANTED.
2. The Trimble County Circuit Court Clerk shall hereby transfer C.A. 10-CI-00227 to the Franklin County Circuit Court Clerk.

So ordered, this _____ day of ___________, 2011.

SPECIAL JUDGE, TRIMBLE CIRCUIT COURT

COMMONWEALTH OF KENTUCKY
12TH JUDICIAL CIRCUIT
TRIMBLE CIRCUIT COURT
CASE NO. 10-CI-00227
DIVISION I

Figure 6: Greenhouse gas allowa... and APA 2010- levelized 2015-2030



KENTUCKY WATERWAYS ALLIANCE,
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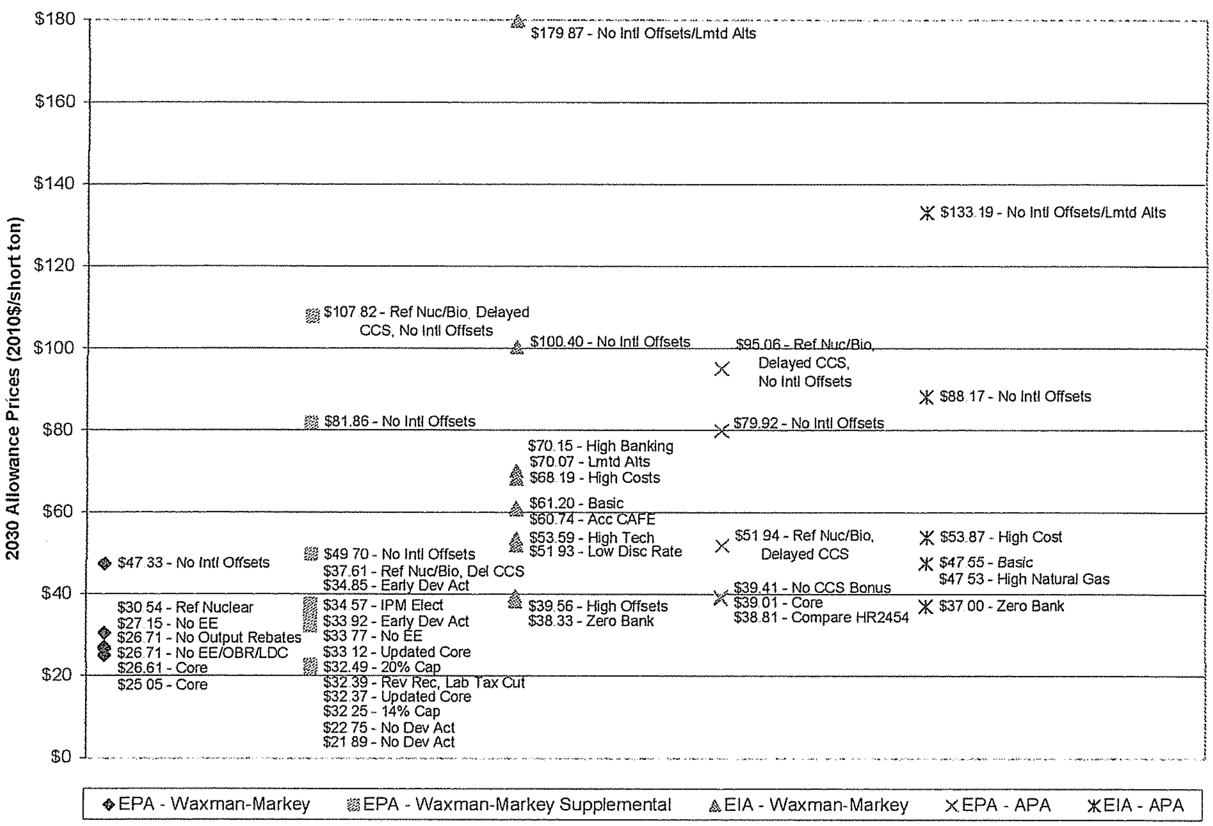
1. Petitioners' Motion to Transfer is GRANTED.
2. The Trimble County Circuit Court Clerk shall hereby transfer C.A. 10-CI-00227 to the Franklin County Circuit Court Clerk.

So ordered, this _____ day of ___________, 2011.

____
SPECIAL JUDGE, TRIMBLE CIRCUIT COURT

Figure 7: 2030 Greenhouse gas allowance price projections for HR 2454 and APA 2010



Our review of the more than 75 scenarios examined in the modeling analyses represented in Figure 7, above, as well as a closer examination of the most recent analyses of legislation considered in the 111th Congress indicates that:

1. Other things being equal, more aggressive emissions reductions will lead to higher allowance prices than less aggressive emissions reductions.

2. Greater program flexibility decreases the expected allowance prices, while less flexibility increases prices. This flexibility can be achieved through increasing the percentage of emissions that can be offset, by allowing banking of allowances or by allowing international trading.

3. The rate of improvement in emissions mitigation technology is a crucial assumption in predicting future emissions costs. For CO_2, looming questions include the future feasibility and cost of carbon capture and sequestration, and cost improvements in integrating carbon-free generation technologies. Improvements in the efficiency of coal burning technologies and in the costs of nuclear power plants could also be a factor. In general, those scenarios in the modeling analyses with lesser availability of low-carbon alternatives have the higher CO_2 allowance prices. When low carbon technologies are widely available, CO_2 allowance prices tend to be lower.

4. Complementary energy policies, such as direct investments in energy efficiency or policies that foster renewable energy resources are a very effective way to reduce the demand for emissions allowances and thereby lower their market prices. A policy scenario which includes aggressive energy efficiency and/or renewable resource development along with carbon emissions limits will result in lower allowance prices than one in which these resources are not directly addressed.

5. Most technologies which reduce carbon emissions also reduce emissions of other criteria pollutants, such as NO_x and SO_2, and mercury. Models which include these co-benefits will predict a lower overall cost impact from carbon regulations, as the cost of reducing carbon emissions will be offset by savings in these other areas. Adopting carbon reduction technology results not only in cost savings to the generators who no longer need criteria pollutant permits, but also in broader economic benefits in the form of reduced permit costs and consequently lower priced electricity. In addition, there are a number of co-benefits such as improved public health, reduced premature mortality, and cleaner air associated with overall reductions in power plant emissions which have a high economic value to society.

6. Projected emissions under a business-as-usual scenario (in the absence of greenhouse gas emission restrictions) have a significant bearing on projected allowance costs. The higher the projected emissions, the higher the projected cost of allowance to achieve a given reduction target.

C. Other forecasts

A number of electric companies include projections of costs associated with greenhouse gas emissions in their resource planning procedures. Table 2, below, summarizes the values used by utilities in their resource plans in the past two years.

Table 2: Values for carbon dioxide used by utilities in resource planning

Utility	Date of IRP (or equivalent)	Model Run	Description
Avista	2009	Base-case	Allowance cost is $46.14 (nominal) and $33.37 (2009 dollars), beginning in 2012. Reaches its high value in 2029.
Idaho Power	2009		$43/ton starting in 2012
LADWP	2010	Base Case	Base case assumes that GHG pricing starts at $20/short ton in 2012 and escalates to $40/short ton in 2020, then escalating at 2.6% annually through 2030. (nominal dollars)
		Low Case	The low case assumes that pricing starts at $15/short ton in 2012 and escalates to $30/short ton in 2020, then escalating at 2.6% annually through 2030. (nominal dollars)
		High Case	The high case assumes that pricing starts at $25/short ton in 2012 and escalates to $50/short ton by 2020 with continued escalation of 2.6% through 2030. (nominal dollars)
Minnesota Power	2010	Base Forecast	$22.11/short ton starting in 2015 and $47.03/short ton in 2024
		Low Forecast	No carbon costs
		High Forecast	$25.66/short ton starting in 2012 and $138.04/short ton in 2024
Nevada Power	2009	Low	Begins at about $10 in 2013 and rises to about $32 in 2039. (2009$/short ton)
		Mid	Begins at about $20 in 2013 and rises to about $70 in 2039. (2009$/short ton)
		High	Begins at about $39 in 2013 and rises to about $138 in 2039. (2009$/short ton)
NorthWestern	2009		Base Case assumes that regs begin in 2013 at $9.55/ton and rises to $80.41/ton in 2030 (2006$). Also cases for earlier and later action.
PacifiCorp	2011	Low	Starting at $12/ton (2015$) in 2015, with 5% annual escalation.
		Medium	Starting at $19/ton (2015$) in 2015, with 5% annual escalation.
		High	Starting at $25/ton (2015$) in 2015, with 7% annual escalation.
		Medium-High	Starting at $19/ton (2009$) in 2015, with 5% annual escalation through 2020; in 2020, escalating at 12% per year. Price reaches $75/ton by 2030.
PGE	2009	Base	Levelized cost of $30/short ton. (2009$)
		Sensitivity	Levelized costs of $12/short ton. (2009$)
		Sensitivity	Levelized costs of $20/short ton. (2009$)
		Sensitivity	Levelized costs of $45/short ton. (2009$)
		Sensitivity	Levelized costs of $65/short ton. (2009$)
PSCo	2010	Base	$20/ton starting in 2014 and escalating at 7% per year
		Sensitivity	$0/ton for all year
		Sensitivity	$40/ton starting in 2014 and escalating at 7% per year
PSE	2009	2007 Trends/2009 Trends	Assumes a CO2 charge of $37/ton starting in 2012, increasing to $130/ton by 2029.
		Green Worlds	CO2 emissiosn cost rise from $55/ton in 2012 to $150/ton in 2029.
		2007 BAU/2009 BAU	$1.60/ton for 20% of the CO2 emitted by plants producing greater than 250 MW. This equates to $0.32/ton, i.e. nearly zero.
Seattle City Light	2010	Basic	In 2007$ per ton. Begins at $20/ton in 2012 and increases to $64.80 in 2030.
		Low	In 2007$ per ton. Begins at $15/ton in 2012 and increases to $41.90 in 2030.
		High	In 2007$ per ton. Begins at $30/ton in 2012 and increases to $106.40 in 2030.
Sierra Pacific	2010		2009$/short ton. Low case begins at about $9 in 2014 and rises to about $31 in 2040. Mid case begins at about $19 in 2014 and rises to about $64 in 2040. High case begins at about $38 in 2014 and rises to about $132 in 2040.
Tri-State	2007	Low	$10/ton (2007$) starting in 2007, escalating at 3% per year
		Mid	$25/ton (2007$) starting in 2007, escalating at 3% per year
		High	$35/ton (2007$) starting in 2007, escalating at 3% per year
SPS (Xcel)	2009		Modeled at $8, $20, and $40 per metric ton, escalated at 2.5%/year consistent with New Mexico PUC Order.
Northern States Power Company (Xcel)	2010		A planning value of $17 per ton CO2 starting in 2012 and escalating at 1.9% per annum. MN Commission high and low externality values are incorporated as sensitivities.

5. Synapse's Recommended February 2011 CO_2 Price Forecast

Our forecast of prices associated with carbon dioxide emissions reflects a reasonable range of expectations regarding the `timing and magnitude of costs for greenhouse gas emissions. We considered what policy developments (e.g. regulation, regional coordination, federal legislation) would lead to costs in the near-term. Our forecast of the range for the mid-term is dominated by projections of legislative compliance costs since those are readily available, rigorous analyses of potential costs under a variety of reduction targets. These are informative even with current uncertainty about federal legislation since they represent the most comprehensive analysis of costs of achieving certain levels of reductions. In the long-term, beyond 2030, we anticipate that costs of emissions will be governed by the costs of marginal abatement technologies. However, our current forecast does not extend beyond 2030. All annual allowance price and levelized values are given in 2010 dollars per short ton of carbon dioxide.[13]

The Synapse February 2011 CO_2 price forecast begins in 2015. This assumption reflects the fact that Congress has lagged behind the states and executive branch in developing a policy response to the science of climate change. The earliest possible action that will affect power generation in all states will likely be regulations from EPA. EPA has agreed to issue final regulations by 2012. Implementation of the regulations, resulting in costs to generators, is likely to be in 2013-2015. That time frame is also consistent with the development of regional emissions cap and allowance trading programs in the West and the Midwest that will affect 13 states beyond the 10 that are already participating actively in the functioning Regional Greenhouse Gas Initiative in the Northeast.

The high bound on our CO_2 Price Forecast starts at $15/ton in 2015, and rises to approximately $80/ton in 2030. Taken as a single trajectory, this High Forecast represents a $43/ton levelized price over the period 2015-2030. This High CO_2 Price Forecast is consistent with the occurrence of one or more of the factors identified above that have the effect of raising prices. These factors include somewhat more aggressive emissions reduction targets, greater restrictions on the use of offsets, restricted availability or high cost of technology alternatives such as nuclear, biomass and carbon capture and sequestration, more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters), or higher baseline emissions.

The low boundary on the Synapse CO_2 price forecast starts at $15/ton in 2020, and increases to approximately $30/ton in 2030. Taken as a trajectory, this represents a $13/ton levelized price over the period 2015-2030. By the year 2020 there is likely to be a price on greenhouse gas emissions either related to achieving greenhouse gas reduction goals, or to adaptation initiatives. A price on carbon affecting power plants throughout the country could come as late as 2020 if legislators fail to act for the next three sessions of congress, and if the President in power is either unable or unwilling to drive federal climate policy. In our opinion, federal legislation is likely by the end of the session in 2018 (with implementation by 2020) spurred by one or more of the following factors:

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[13] All values in the Synapse Forecast are presented in 2010 dollars. Results from EIA and EPA modeling analyses were converted to 2010 dollars using price deflators taken from the US Bureau of Economic Analysis, and available at: http://www.bea.gov/national/nipaweb/SelectTable.asp Because data were not available for 2010 in its entirety, values used for conversion were taken from Q3 of each year. Consistent with EIA and EPA modeling analyses, a 5% real discount rate was used in all levelization calculations.

technological opportunity; a patchwork of state policies to achieve state emission targets for 2020 spurring industry demands for federal action; a Supreme Court decision to allow nuisance lawsuits to go ahead resulting in a financial threat to energy companies; and increasingly compelling evidence of climate change. Given the interest and initiatives on climate change policies in states throughout the nation, a lack of federal action will result in a hodge podge of state policies. This scenario is a nightmare for any company that seeks to make investments in existing, modified, or new power plants. Historically, just such a pattern of states and regions leading with initiatives that are eventually superseded at a national level is common for energy and environmental policy in the US. It seems likely that this will be the dynamic that ultimately leads to federal action on greenhouse gases, as well.

The low forecast boundary is consistent with the coincidence of one or more of the factors discussed above that have the effect of lowering prices. For example, this price boundary may represent a scenario in which Congress begins regulation of greenhouse gas emissions slowly by either:

1. including a very modest or loose cap, especially in the initial years,
2. including a safety valve price or
3. allowing for significant offset flexibility, including the use of substantial numbers of international offsets.

The factors could also include state actions to reduce emissions through aggressive energy efficiency and renewable actions, and/or a decision by Congress to adopt a set of aggressive complementary policies as part of a package to reduce CO_2 emissions. These complementary policies could include an aggressive federal Renewable Portfolio Standard, more stringent automobile CAFE mileage standards (in an economy-wide regulation scenario), and/or substantial energy efficiency investments. Such complementary policies would lead directly to a reduction in CO_2 emissions independent of federal cap-and-trade or carbon tax policies, and would thus lower the expected allowance prices associated with the achievement of any particular federally-mandated goal.

The range of prices we have shown is recommended for planning purposes, but it is certainly possible that the actual price will fall outside of this range. For example, there are some CO_2 price scenarios identified in recent analyses that are significantly higher than our Synapse High Price Forecast. These scenarios represent situations with limited availability of alternatives to carbon-emitting technologies and/or limited use of international and domestic offsets. We do not believe that the CO_2 prices characteristic of such scenarios are likely in the current political environment, given that there may be avenues available for meeting likely emissions goals that would mitigate costs to below these levels. However, the political context may change over time due to changes in technical, economic, and political circumstances, and/or developments in scientific evidence on the rate and impacts of a changing climate.

Synapse also has prepared a Mid or Expected CO_2 Price Forecast that starts a bit more slowly, but close to the low case, at \$15/ton in 2018, but then climbs to \$50/ton by 2030. The levelized cost of this mid CO_2 price forecast is \$26/ton over the period 2015 to 2030.

The 2011 Synapse High, Mid and Low CO_2 Price Forecasts are shown in Figure 8 and Table 3 below.

Figure 8: 2011 Forecast Values

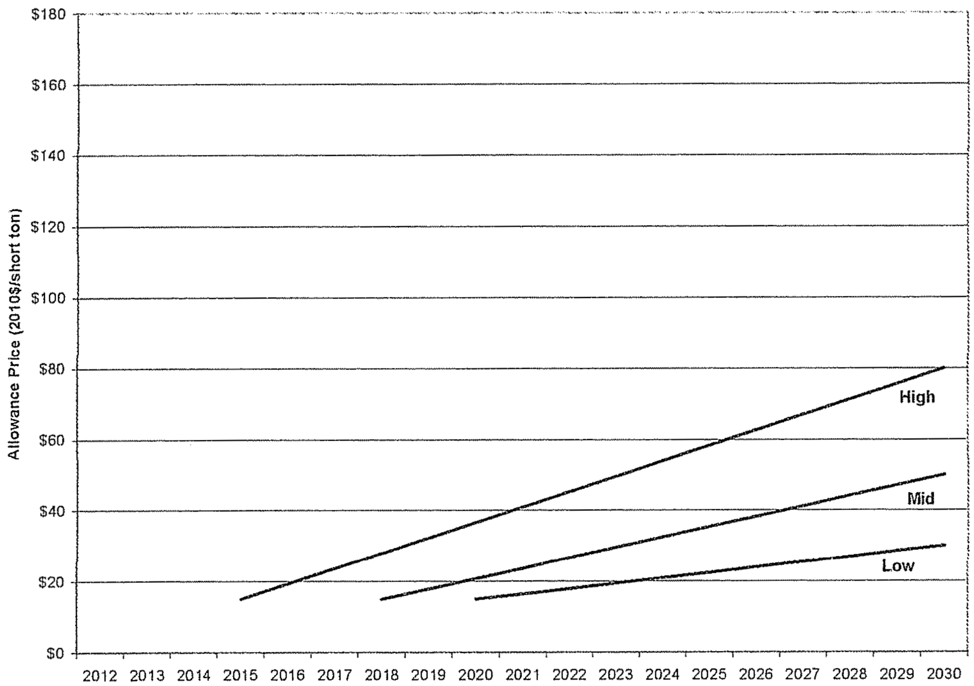
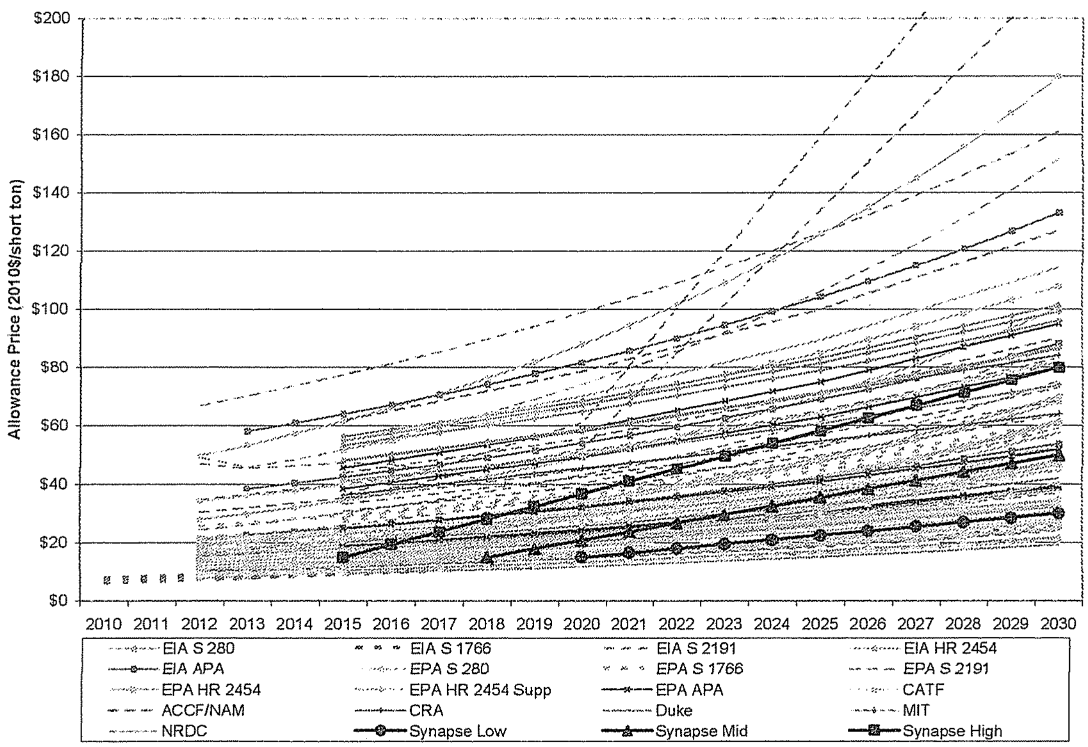


Table 3: 2011 Synapse Low, Mid, and High CO_2 Allowance Price Forecasts (2010$/short ton)

Year	Low Case	Mid Case	High Case
2015	N/A	N/A	$15.00
2016	N/A	N/A	$19.33
2017	N/A	N/A	$23.67
2018	N/A	$15.00	$28.00
2019	N/A	$17.92	$32.33
2020	$15.00	$20.83	$36.67
2021	$16.50	$23.75	$41.00
2022	$18.00	$26.67	$45.33
2023	$19.50	$29.58	$49.67
2024	$21.00	$32.50	$54.00
2025	$22.50	$35.42	$58.33
2026	$24.00	$38.33	$62.67
2027	$25.50	$41.25	$67.00
2028	$27.00	$44.17	$71.33
2029	$28.50	$47.08	$75.67
2030	$30.00	$50.00	$80.00

It is important to emphasize that these are price trajectories to use for planning purposes, so that a reasonable range of emissions costs can be incorporated to reflect likely costs of alternative resource plans, for example. We do not expect carbon prices to follow any single trajectory in our forecast. Rather, our forecast can be read as the expectation that in 2015 the price will be between $0 and $15 in 2010 dollars, and in 2025 it will be between $23 and $58. It is entirely possible that the price will start out quite low, as Congress "tests the waters" on carbon policy, and rise closer to our high case as the need for greater emissions reductions becomes increasingly evident, more technological options become available, and the economy and the electorate adjust to paying for carbon emissions. Just such a scenario was recently applied by Pacificorp in their proposed Integrated Resource Plan.[14] Their "Low to Very High" trajectory begins at $12/ton in 2015 (2015 dollars) and grows at only 3%/year in real terms until 2020, and then at 18% real escalation thereafter. Converted into 2010 dollars, this scenario has a levelized cost almost exactly the same as Synapse' "Mid" case presented here. Figures 9 through 13, below, place the Synapse February 2011 forecast in context. They present the Synapse February 2011 forecast alongside projections of greenhouse gas allowance prices associated with federal legislative proposals discussed in previous sections of this report.

Figure 9: Synapse CO_2 trajectories and greenhouse gas allowance price projections based on analyses of federal legislative proposals



[14] Pacificorp, "Portfolio Development Cases for the 2011 Integrated Resource Plan", December 7, 2010.

Figure 10: Synapse CO_2 trajectories and greenhouse gas allowance price projections based on analyses of federal legislative proposals – levelized

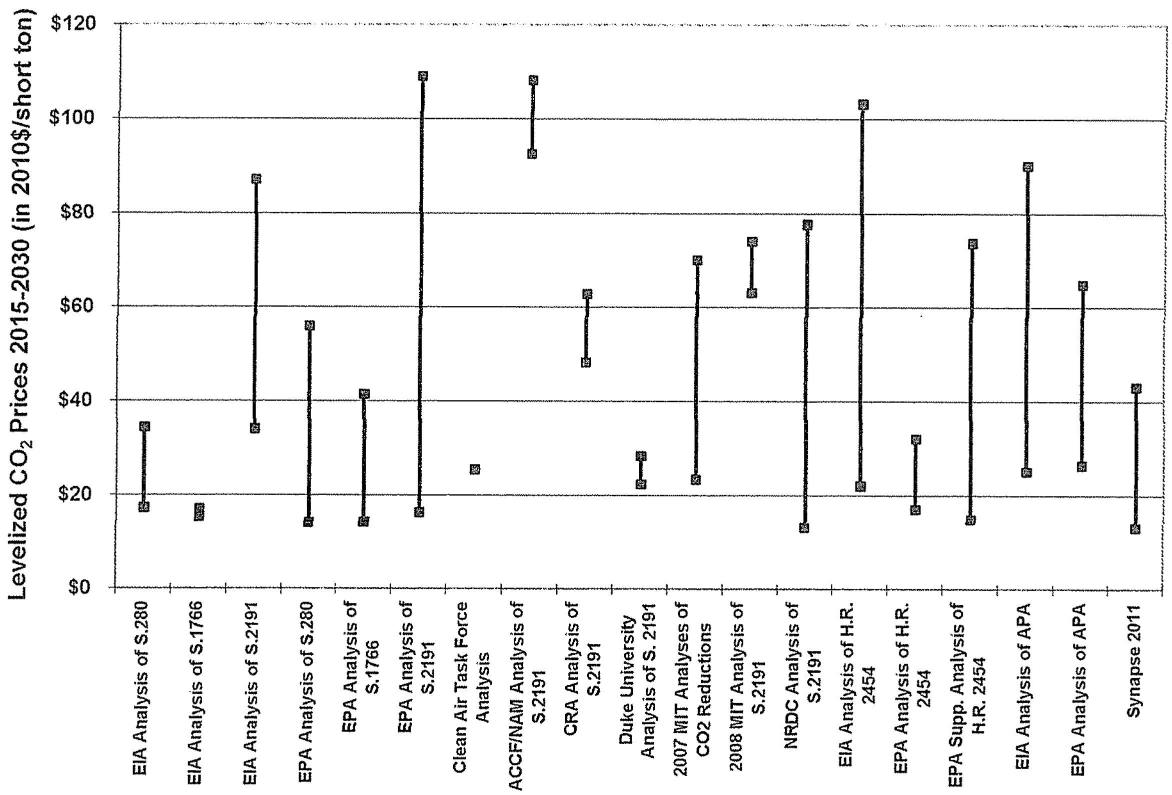


Figure 11: Synapse CO_2 trajectories and greenhouse gas allowance price projections for HR 2454 and APA 2010

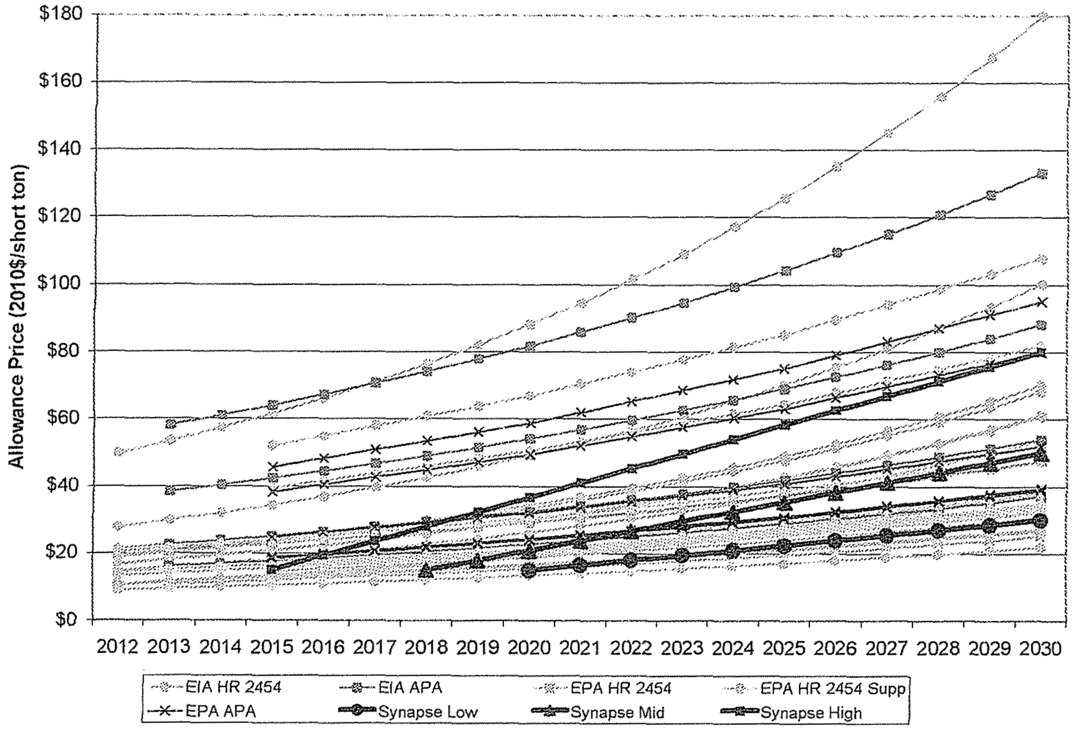


Figure 12: Synapse CO_2 trajectories and greenhouse gas allowance price projections for HR 2454 and APA 2010- levelized 2015-2030

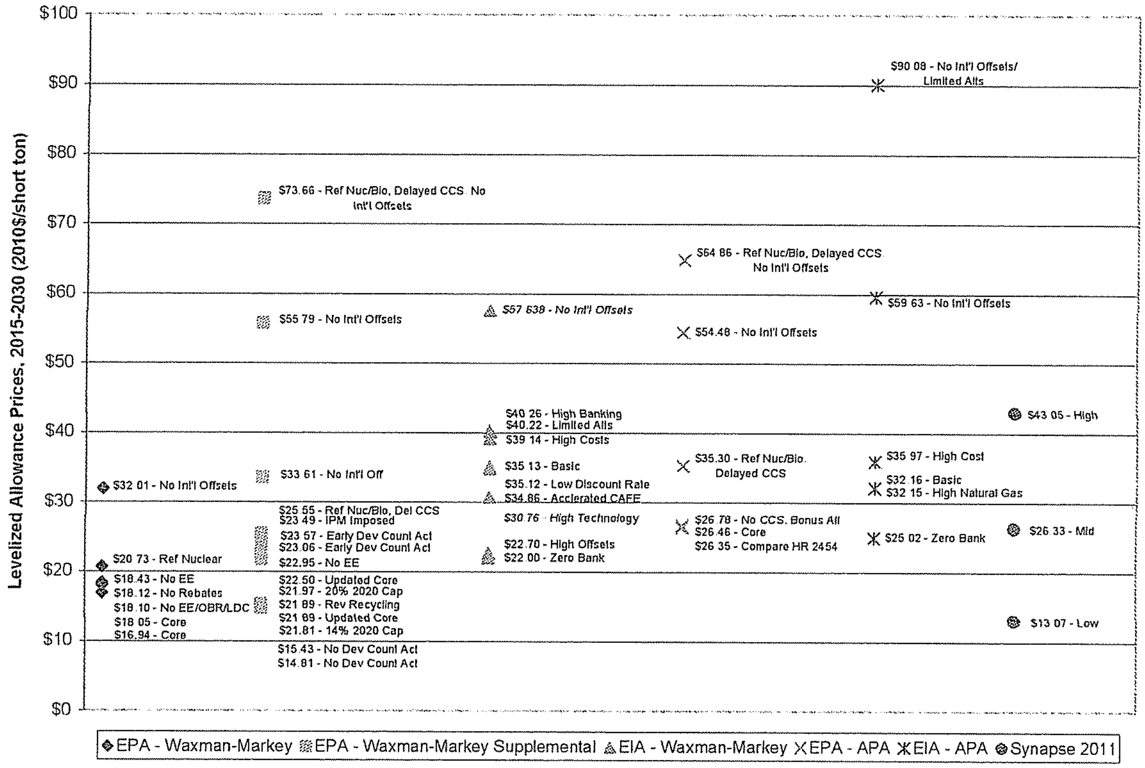
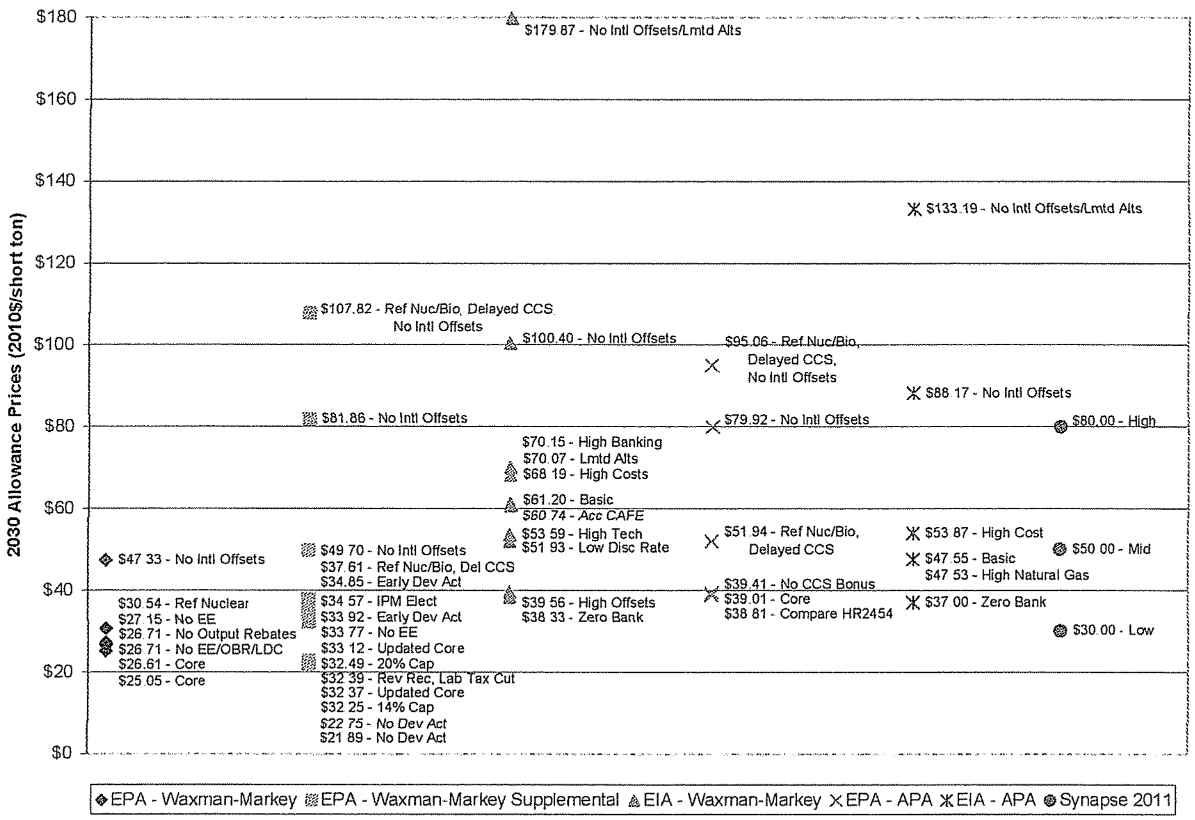


Figure 13: 2030 Synapse CO_2 prices and greenhouse gas allowance price projections for HR 2454 and APA 2010



The Synapse projections represent a range of possible future costs. These recommended price trajectories will be useful for testing range-sensitivity of various investment possibilities in resource planning in the electric sector. There will certainly be variability and volatility in prices following supply and demand dynamics, as there is with other cost drivers Nonetheless, we intend and anticipate that the projections represent a useful price range for resource planning and policy analysis in the face of uncertainty.

6. Conclusion

The lack of clarity on the future of climate change policies in the United States does not diminish the importance of appropriate consideration of likely future emissions costs in electric resource planning. To the contrary, a reasonable projection of a range of costs is critical to investment decisions and the selection of least-cost resource plans that will be robust under a variety of circumstances. As the most comprehensive source of information on potential costs under a variety of emission reduction scenarios, analyses of recent legislative proposals provide useful insight in developing a reasonable emissions price projection. These analyses of legislative proposals provide information that is useful in considering a variety of policy futures – well beyond those that *include a national emissions cap and allowance trading program. They explore the dynamic* relationship between factors such as emission reductions, technology innovation, flexibility mechanisms (such as offsets), penetration of clean energy sources and efficiency, and others – all of which come into play under a variety of policy mechanisms. The Synapse February 2011 Carbon Forecast represents a reasonable range of values to use in investment decisions and resource selection. The range presented does not include the most extreme high or low values, which derive from a combination of factors that can reasonably be deemed unlikely to occur in combination. Rather, it represents a reasonable range to use for purposes of robust analysis of resource plans and policy options, recognizing that the future will always involve uncertainty.

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Attachment 2.10-1

Performance Proven

Analysis of "Loss of Load Probability" (LOLP) at various Planning Reserve Margins

Prepared for:
Public Service Company of Colorado

Date Submitted:
December 1, 2008

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Attachment 2.10-1

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EXECUTIVE SUMMARY

At the request of Public Service Company of Colorado (PSCo), Ventyx performed a stochastic analysis of the relationship between electric generating capacity reserve margin (aka, planning reserves) and the ability of the PSCo system to reliably maintain service to load. The analysis focused on the year 2013 and accounts for PSCo existing and expected generation resources and the anticipated availability characteristics of those resources. The analysis takes into consideration PSCo's hourly customer electric demands and the volatility of those demands due to weather. The analysis incorporates a representation of the reliability support that PSCo can expect to receive from the Rocky Mountain Reserve Group (RMRG) under single contingency events of 200 MW or greater. The reserve margin study also incorporates PSCo's obligation to carry approximately 419 MW of operating reserves for year 2013 as part of its membership in the RMRG. Additionally, the analysis considers the reliability contribution of transmission lifeline capacity generally reserved for system emergencies.

Ventyx performed the analysis using the Market Analytic's Planning & Risk Module (PaR). The load, wind generation, and unit availability were treated stochastically. The level of energy not served from the PaR modeling work was used to determine the expected level of reliability for the system for different levels of capacity reserve margin. The analysis indicates that a Planning Reserve Margin of 16.3% would provide an expected probability that the PSCo system would be unable to serve firm load customers approximately 1-day-in-10-years. This level of reliability is considered acceptable and often used as a standard for reliable systems within the electric utility industry.

1 RECENTLY ACCEPTED APPROACHES

1.1 PREVIOUS LOLP STUDIES

In 2003 Resource Plan Filings with the California Public Utility Commission, three different Investor Owned Utilities (PG&E, SCE, and SDG&E) all performed portfolio stochastic analysis to assess appropriate levels of planning reserves. In these analyses, the utilities selected an upcoming applicable year and tested the ability of their power supply systems to meet customer loads in that year under different utility supply portfolios that gave different levels of planning reserve. The methodology involved performing hourly economic dispatch of resources against loads for each hour of the year. Because of the uncertainties of unit forced outage and load level variations caused by weather, multiple iterations of the year were performed. Under each iteration, Monte Carlo draws were made daily that adjusted load levels either upward or downward. Further, Monte Carlo draws were made to reflect possibilities of unit forced outage. The California PUC accepted the methodology at that time, but more recently some utilities have indicated that higher reserve margins should be required because of the possibility of non-performance of PPAs, etc. The California PUC has therefore opened another proceeding to discuss possible changes to reflect these matters.

It is typical to use a 1-day-in-10-year Loss of Load Probability (LOLP) when determining the needed Planning Reserve Margin. This level of LOLP is equivalent to failing to serve the energy requirements of the system for 2.4 hours each year or 24 hours during a 10-year period.

2 PSCO FOCUSED ANALYSIS USING PORTFOLIO STATISTICAL ANALYSIS AND EXPECTED ENERGY NOT SERVED (ENS)

2.1 OVERVIEW OF ANALYSIS PERFORMED

Ventyx has performed a stochastic analysis of Loss of Load Probability on the PSCo system in a manner similar to the analysis performed by California investor owned utilities in the year 2003 and accepted by the California PUC as well as by PSCo in 2004 (filed with PSCo's 2003 LCP). In particular, Ventyx focused on PSCo existing and expected generation resources and loads in year 2013. The analysis also reflects a PSCo operating reserve of 419 MW, which represents PSCo's expected operating reserve obligation under the RMRG after the Comanche 3 unit becomes operational.

Ventyx utilized its regional Market Analytics software module, Planning & Risk, to perform this stochastic reserve margin analysis of the PSCo system. The key factors represented stochastically in this analysis are:

- Unit forced outages and maintenance,
- Weather related load volatility,
- Wind generation, and
- Transmission lifeline capacity.

Ventyx stochastically simulated the hourly dispatch of the PSCo system for year 2013, where Monte Carlo draws were performed for 100 iterations in order to capture the impact of uncertainties in these key factors.

2.2 TEST YEAR FOR ANALYSIS

Consistent with PSCo's 2007 CRP, PSCo provided the portfolio of resources, wind pattern, unit maintenance and forced outages and the hourly load forecast for the year 2013 for the purpose of this study.

2.3 RESOURCES IN THE BASE YEAR

PSCo generation resources in the year 2013 reflected in the analyses are listed in Table 1 below. The Comanche 3 facility was modeled at it full expected capacity of 784 MW and the full load requirements of IREA and Holy Cross were included in the modeling of customer demand (i.e., as opposed to modeling only PSCo's share of Comanche 3 and removing the portion of IREA and Holy Cross's load that will be served by their ownership share of Comanche 3).

Table 1
Public Service of Colorado expected 2013 Summer Resource Capacity

Resource	Peak Capacity MW	Resource	Peak Capacity MW	Resource	Peak Capacity MW	Resource	Peak Capacity MW
Alamosa 1	12.82	Comanche 1	325	Hayden 1	139	Sunshine Hydro	0.7
Alamosa 2	13.5	Comanche 2	335	Hayden 2	99	Tacoma Hydro	8.5
AMES HYDRO	3.75	Comanche 3	784	HillCrest Hydro	2.3	Thermo RS1 31CC	152
Arapahoe CC	479	Craig 1	41.6	Kohler Hydro	0.15	Tower04WT	42.12
Basin1 LRS2	50	Craig 2	41.6	LakeGeorge Hydro	0.23	Tower41WT	98.75
Basin1 LRS3	50	CT_129_A	258.6	Manchief CT	260.7	Tower49WT	41.37
Basin2 LRS2	37.5	Dillon Hydro	1.9	Maxwell Hydro	0.15	Tri2 Craig1	9.93
Basin2 LRS3	37.5	Foothills Hydro	2.3	On_Site Solar	11.89	Tri2 Craig2	9.93
Betasso Hydro	8.57	Fruita	15	Orodell Hydro	0.22	Tri2 Craig3	38.29
BioGas 75th ST	0.5	FSV CC 1x1	226	Ouray Hydro	0.5	Tri2 LRS2	19.18
BioMass	4	FSV CC 2x1	252	Palisade Hydro	1.7	Tri2 LRS3	19.18
Brush 13	75	FSV CC 3x1	230	Pawnee 1	505	Tri3 Craig1	2.49
Brush 4D CC2	133	FSV CT	270	PlainsEnd2 CC	224	Tri3 Craig2	2.49
Cabin Crk Gen1	105	Ft Lupton 1	44.7	Redlands Hydro	1.4	Tri3 Craig3	9.84
Cabin Crk Gen2	105	Ft Lupton 2	44.7	Roberts T Hydro	6.1	Tri3 LRS2	4.8
Central Solar	11.12	Georgetown Hydro	1.2	Rocky Mtn CC21	601	Tri3 LRS3	4.8
Cherokee 1	107	Gross Res Hydro	8.1	Salida Hydro	1.4	TST Brighton	132
Cherokee 2	106	Spindle_CT	269	Shoshone Hydro	15	TST Limon	66
Cherokee 3	152	SPS TieLine	101	Stagecoach Hydro	0.8	UNC Greeley EXT	68.86
Cherokee 4	352	Valmont 6	43	Strontia Hydro	1.2	Valmont 5	186
Cherokee Diesel	5.5	WM Landfill Gas	3.2	SunEdison Solar	2.87		

(Wind contributed 12.5% of nameplate, Solar at 58% and Cabin Creek 210 MW)

In the analysis, the PSCo wind generation resources were lumped together into three distinct geographic zones: Colorado/Wyoming border zone near the existing Ponnequin facility, northeast zone near Peetz Table, and the southern zone near the Colorado Green facility. The three wind zones provide geographic diversity for wind generation based on the modeling techniques applied for stochastic wind generation discussed later in this report. For the calculation of planning reserves, the wind capacity is counted at 12.5% of their nameplate capacity.

2.4 YEAR 2013 LOADS

The analysis applied Monte Carlo draws on load to reflect the likelihood that loads will be higher or lower as a result of weather, than what is being forecast for year 2013. To perform this type of Monte Carlo analysis, an hourly profile of PSCo loads for the year 2013 was developed. The forecasted peak demand for year 2013 is 7,310 MW, which is comprised of the September 2007 peak demand of 7,094 MW and an additional 216 MW of coincident peak demand from IREA and Holy Cross. As seen above Comanche 3 was modeled at its full capacity to accommodate serving the full load requirements of IREA and Holy Cross. While IREA and Holy Cross will have a 250 MW share of the Comanche 3 unit, it is expected that only 216 MW of load would be coincidental with the PSCo peak demand and only that coincident amount was considered for the total 2013 PSCo peak demand. As described above, PSCo's portion of Comanche 3 and IREA's and Holy Cross's portion of Comanche 3, totaling to 784 MW of capacity for Comanche 3, was also included since IREA and Holy Cross wholesale load requirements were included as part of the PSCo load.

2.4.1 Load Stochastic Process and Volatility Parameters

The stochastic model used to perform the stochastic draws on load is a two-factor model in which one factor represents short-term or temporary deviations and the other factor represents long-term or cumulative deviations. Long-term effects include trends such as change in annual peak demand growth and other forces whose effects are of long duration, which follow a random walk. In the short term, shocks may drive variables away from their long-term equilibrium level, but adjustment processes tend to pull them back to their equilibrium or expected level in the short term. In other words, short-term shocks such as changes to load due to weather are mean reverting. The rate at which the random variable tends to revert to the expected value is an input to the process. This is referred to as the mean reversion rate. The two-factor model combines the short-term mean reverting process with the long-term random walk process.

The volatility estimates for PSCo load in this study were developed from historical hourly load data from 1996-2007. The estimated short-term stochastic parameters for PSCo load, used as inputs into the Planning & Risk models stochastic analysis, are presented in Table 2 below. Long-term stochastic parameters were not necessary since the study period is a single year. As a result of these stochastic parameter inputs, a distribution of load volatility is created.

Table 2
PSCo Load Stochastic Parameters

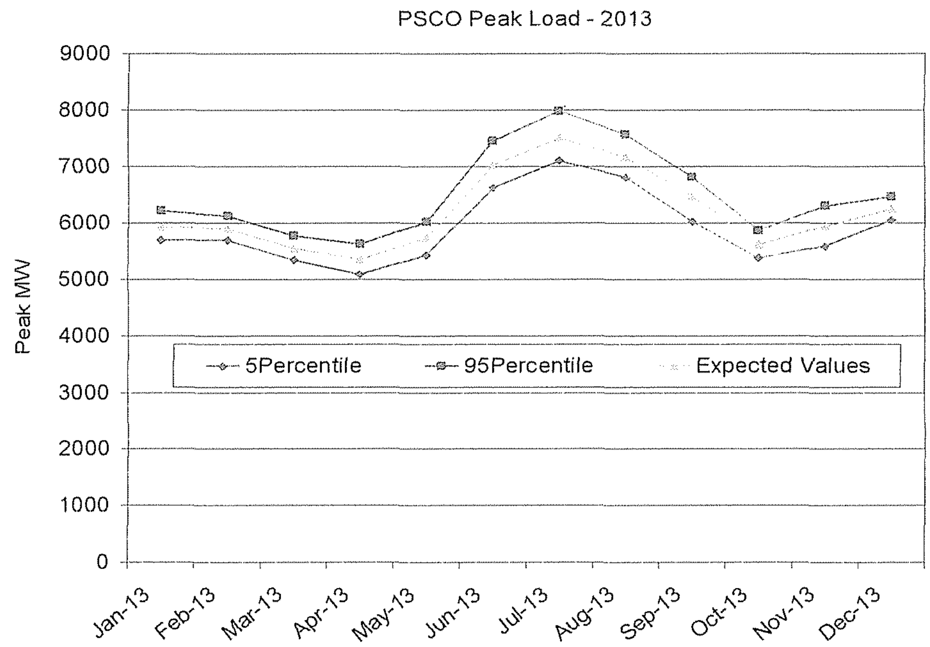
Season[1]	Load PSCo	
2013	Alpha	Sigma
Winter	0.275	0.014
Spring	0.266	0.015
Summer	0.195	0.016
Fall	0.276	0.019

Source: Ventyx.

Figure 1 illustrates the 5th, Average, and 95th confidence intervals of load distribution for the year 2013.

[1] Season definition: Winter = December-February; Spring = March-May; Summer = June-August; Fall = September-November. Sigma is the volatility parameter and alpha is the mean reversion parameter.

Figure 1
PSCo Load Distribution - Confidence Intervals



2.5 MODELING OF WIND VOLATILITY

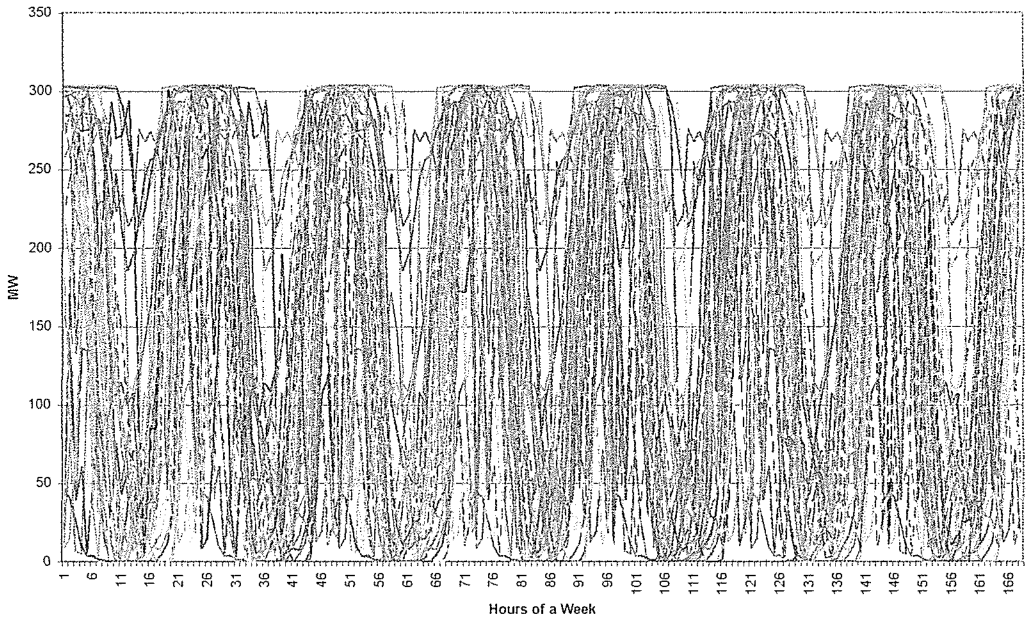
Using historical hourly wind generation from existing PSCo wind facilities, Ventyx created 100 different hourly wind patterns that reflect the unpredictable nature of the PSCo wind resource. PSCo provided wind shapes for three wind zones: Colorado/Wyoming border, northeast Colorado, and southeast Colorado. These three wind shapes were utilized to model wind variability within the analysis.

The stochastic wind data was developed external to the Planning & Risk model, and introduced during model simulation. The following method was used in creating the stochastic wind data:

1. Hourly historical wind shapes for the three locations were developed and each fluctuates differently due to their location and associated wind pattern.
2. To capture the randomness of wind generation, Ventyx used its Hourly Historical Simulation Tool, which randomizes daily-hourly profiles within a month. This process was repeated for each aggregated wind location. For example, in creating the 24-hour by 100 iterations of data for January 1 for a location, the random number generator picked which hourly day profile in January to choose. Since January has 31 days, the random number generator chose any one of the 31 days of January for each of the 100 iterations for January 1. So for January 1, iteration 1 may use the hourly profile of day 30 of January, iteration 2 may use the hourly profile of day 2 of January and so on. This process was continued until all days of the year for each of the 100 iterations was developed. Figure 2 shows the stochastic wind data for a representative week in July.

3. The randomized wind data was then fed into Planning & Risk through XML integration and included in the model simulation.

Figure 2
PSCo Stochastic Wind Data for a Location



2.6 FORCED OUTAGE RATES ON SUPPLY RESOURCES

The expected level of forced outages for PSCo units (both owned and purchased) was estimated from actual historical availability data. The model assumed the following expected levels of forced outage rates on the following supplies.

Table 3
Public Service of Colorado Station Outage Rate

Station	EFOR	Station	EFOR	Station	EFOR
Alamosa 1	0.10%	Dillon Hydro	5.00%	Rocky Mtn CC21	5.00%
Alamosa 2	0.10%	Foothills Hydro	5.00%	Salida Hydro	3.00%
AMES HYDRO	6.00%	Fruita	7.30%	Shoshone Hydro	1.00%
ArapCC	1.60%	FSV CC 1x1	2.50%	Spindle_CT	3.00%
Basin1 LRS2	3.00%	FSV CC 2x1	2.50%	SPS TieLine	0.50%
Basin1 LRS3	3.00%	FSV CC 3x1	2.50%	Stagecoach Hydro	5.00%
Basin2 LRS2	3.00%	FSV CT	3.00%	Strontia Hydro	5.00%
Basin2 LRS3	3.00%	Ft Lupton 1	9.50%	Sunshine Hydro	5.00%
Betasso Hydro	5.00%	Ft Lupton 2	17.20%	Tacoma Hydro	5.00%
BioGas 75th ST	3.00%	Gen GT	3.60%	Thermo RS1 31CC	3.00%
BioMass	10.00%	Georgetown Hydro	2.00%	Tri2 Craig1	4.80%
Brush 13	2.00%	Gross Res Hydro	5.00%	Tri2 Craig2	4.80%
Brush 4D CC2	2.00%	Hayden 1	6.60%	Tri2 Craig3	3.00%
Cabin Crk Gen1	6.00%	Hayden 2	3.50%	Tri2 LRS2	3.00%
Cabin Crk Gen2	6.00%	HillCrest Hydro	5.00%	Tri2 LRS3	3.00%

Station	EFOR	Station	EFOR	Station	EFOR
Cherokee 1	9.50%	Kohler Hydro	5.00%	Tri3 Craig1	4.80%
Cherokee 2	12.40%	LakeGeorge Hydro	5.00%	Tri3 Craig2	4.80%
Cherokee 3	10.10%	Manchief CT	5.00%	Tri3 Craig3	3.00%
Cherokee 4	8.90%	Maxwell Hydro	5.00%	Tri3 LRS2	3.00%
Cherokee Diesel	9.40%	Orodell Hydro	5.00%	Tri3 LRS3	3.00%
Comanche 1	13.30%	Ouray Hydro	5.00%	TST Brighton	5.00%
Comanche 2	4.40%	Palisade Hydro	3.00%	TST Limon	5.00%
Comanche 3	6.30%	Pawnee 1	8.40%	UNC Greeley EXT	5.00%
Craig 1	4.80%	PlainsEnd2 CC	1.50%	Valmont 5	4.20%
Craig 2	4.80%	Redlands Hydro	5.00%	Valmont 6	9.90%
CT_129_A	1.00%	Roberts T Hydro	5.00%	WM Landfill Gas	5.00%

Table continued on next page.

100 iterations of the model were run for year 2013. Monte Carlo draws determined if a resource was on forced outage or not. In this case, the model was set up so that if a unit was forced out in a week as a result of a Monte Carlo draw, the unit is assumed out for the entire week. If a unit has an expected forced outage rate of, for example, 5%, then the average outage hours for that unit over the 100 iterations is 5% of the time. However, any individual iteration could have an outage rate for that iteration for the year of greater or less than 5%. The Monte Carlo draws are designed such that over a large number of random draws of unit outage, statistically one would expect the average hours of unit being forced out during a year to be 5%. However, statistically it is possible that over 100 iterations the average outage rate is slightly above or below the 5% number.

2.7 Rocky Mountain Reserve Group Support

One key aspect of the analysis was to reflect the reliability support that PSCo receives from neighboring electric systems. PSCo is a member of the Rocky Mountain Reserve Group (RMRG) and thus has the right to call for support from the group under certain qualifying contingency events. In accordance with the RMRG rules, PSCo must notify the RMRG group and may request group support for outages of PSCo plants of 200 MW and larger. For outage events of less than 200 MW, PSCo is not required to notify the RMRG group and generally covers the event using its own reserves. For this analysis Ventyx reflected RMRG support to PSCo for outages of plants of 200 MW or larger. Table 4 shows the RMRG Response Matrix and the contingency assistance provided to PSCo by the RMRG Members. The RMRG support contained in Table 4 is based on the individual members' forecasts of load for year 2013.

The RMRG Response Matrix details the amount of contingency assistance provided to PSCo at different megawatt levels of outages. The contingency assistance by RMRG rules is available only for the hour of the event and the following hour for a total of 2 hours per outage event per month. If multiple units are out at the same time, the contingency assistance is provided to the unit with largest capacity.

Based on the RMRG response matrix, Ventyx calculated the RMRG contingency assistance provided by the participating surrounding utilities to PSCo for the PSCo units above 200 MW. Table 5 summarizes the RMRG assistance available for each unit.

Table 4
Rocky Mountain Reserve Group Response Matrix

		B1	B2	B3	B4	B5	B6	B7	B8	B9	B10	B11	B12	B13	B14
RMRG responsibilty					**784**	**759**	**734**	**709**	**684**	**659**	**634**	**609**	**584**	**559**	**534**
EMERGENCY ASST * -> FOR PSCO					391	378	367	354	341	329	317	305	294	283	269
	RRR	**Member response requirement**													
MEAN	0 011756				10	9	9	9	8	8	8	7	7	7	7
WMPA	0 002232				2	2	2	2	2	2	1	1	1	1	1
TRIS	0 108974				88	85	83	80	77	75	72	69	66	64	61
BHPL	0 035493				29	28	27	26	25	24	23	23	22	21	20
CSU	0 074984				61	59	57	55	53	51	49	48	46	44	42
FRPC	0 007988				6	6	6	6	6	5	5	5	5	5	4
WACM	0 062762				51	49	48	46	44	43	41	40	38	37	35
					0	0	0	0	0	0	0	0	0	0	0
WALC	0 034187				28	27	26	25	24	23	23	22	21	20	19
					0	0	0	0	0	0	0	0	0	0	0
PRPA	0 060373				49	47	46	44	43	41	40	38	37	35	34
WPEC	0 014808				12	12	11	11	10	10	10	9	9	9	8
PSCO	0 517850				419	406	393	380	367	354	341	328	315	302	289
BEPC	0.068591				55	54	52	50	49	47	45	43	42	40	38
GROUP	1.0000				810	784	760	734	708	683	658	633	609	585	558
WACM AGC offsets					-297	-288	-282	-274	-265	-258	-249	-243	-235	-229	-220
After 15 minutes, change to.					-247	-238	-232	-224	-215	-208	-199	-193	-185	-179	-170
PSCO AGC offsets					-225	-215	-208	-199	-189	-181	-172	-165	-156	-149	-139
After 15 minutes, change to.					-275	-265	-258	-249	-239	-231	-222	-215	-206	-199	-189
WACM AGC offsets						-318	-312	-304	-295	-288	-279	-273	-265	-259	-250
After 10 minutes, change to.						-288	-282	-274	-265	-258	-249	-243	-235	-229	-220
PSCO AGC offsets						-245	-238	-229	-219	-211	-202	-195	-186	-179	-169
After 10 minutes, change to.						-315	-308	-299	-289	-281	-272	-265	-256	-249	-239
WALC AGC offsets					-28	-27	-26	-25	-24	-23	-23	-22	-21	-20	-19

		B18	B19	B20	B21	B22	B23	B24	B25	B26	B27	B28	B29	B30	B31
RMRG responsibilty		**434**	**409**	**384**	**359**	**334**	**309**	**284**	**259**	**234**	**209**	**184**	**159**	**134**	**109**
EMERGENCY ASST * -> FOR		218	206	194	182	171	161	147	135	123	111	89	76	65	53
	RRR	**Member response requirement**													
MEAN	0.011756	5	5	5	4	4	4	4	3	3	3	2	2	2	1
WMPA	0.002232	1	1	1	1	1	1	1	1	1	1	0	0	0	0
TRIS	0.108974	49	47	44	41	39	36	33	30	28	25	20	17	15	12
BHPL	0.035493	16	15	14	13	13	12	11	10	9	8	7	6	5	4
CSU	0.074984	34	32	30	28	27	25	23	21	19	17	14	12	10	8
FRPC	0.007988	4	3	3	3	3	3	2	2	2	2	1	1	1	1
WACM	0.062762	28	27	25	24	22	21	19	18	16	14	12	10	8	7
	0.000000	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WALC	0.034187	16	15	14	13	12	11	10	10	9	8	6	5	5	4
	0.000000	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRPA	0.060373	27	26	24	23	21	20	18	17	15	14	11	10	8	7
WPEC	0.014808	7	6	6	6	5	5	5	4	4	3	3	2	2	2
PSCO	0.517850	235	222	209	196	195	178	157	144	132	119	95	82	69	56
BEPC	0.068591	31	29	28	26	24	23	21	19	17	16	13	11	9	7
GROUP	1.0000	453	428	403	378	366	339	304	279	255	230	184	158	134	109
WACM AGC offsets		-137	-130	-122	-114	-109	-102	-93	-85	-78	-70	-56	-48	-41	-33
PSCO AGC offsets		-153	-145	-136	-127	-121	-113	-103	-95	-87	-78	-62	-53	-46	-37
WALC AGC offsets		-16	-15	-14	-13	-12	-11	-10	-10	-9	-8	-6	-5	-5	-4

Table 5
RMRG Contingency Assistance for PSCo Units Greater than 200 MW

PSCo Units > 200 MW	Capacity MW	RMRG Contingency Assistance MW (shadow station)
Comanche3	784	391
RockyMontCC2	601	301
Pawnee1	505	253
Cherokee4	352	179
Comanche2	335	171
Comanche1	325	167
RockyMontCC1	259	135
FSV2	252	132
FSV3	230	121
FSV1	226	119
Plainsend2	224	118

2.7.1 Modeling the RMRG Support

For each PSCo units ≥ 200 MW, Table 5, Ventyx modeled a corresponding RMRG support unit called a shadow station. The size of each RMRG shadow station was determined by the actual plant size and the corresponding assistance available as reported in Table 5.

To reflect the fact that each RMRG shadow station may only be called upon during its parent station's outage event, PaR Rules of Existence (Rule Groups) modeling was utilized. Rule Group modeling included assigning each of the RMRG Shadow Units to a Rule that tells PaR the RMRG unit can exist to help serve load only if the parent station is on outage.

Since only the largest station during overlapping outages receives the RMRG contingency assistance, a Rule Group hierarchy of RMRG shadow stations was implemented to ensure only the largest contingency was called upon.

Under the terms of the RMRG, pool members are required to provide contingency assistance to PSCo, if requested, for up to two hours for each qualifying contingency event. To reflect this real-life constraint, Ventyx modeled the RMRG Shadow Units as "limited energy" stations. For each of the RMRG shadow stations Ventyx input a weekly energy limit equal to 2 times the MW rating of the shadow unit (i.e., 2-hours of full load operation). Once the RMRG unit is been called upon in the modeling, it will not be available again for contingency assistance until the next outage. As a limited energy station, PaR will attempt to choose the best hours to run limited energy RMRG shadow station based on dispatch economics. For instance, if a 300 MW PSCo plant is tripped off-line at 12 am and is forced out for the week, PaR will not immediately activate the RMRG shadow station but rather will attempt to save the limited energy from the shadow unit for peak hours or for hours where energy not served exists. In other words, because the RMRG shadow stations are modeled with such a high cost of operating (i.e. just below the cost of ENS), the units will only be run when there would otherwise by ENS, and the units will only run for two hours following each outage. This methodology allowed the RMRG unit to be available to contribute generation assistance to PSCo after the station goes on forced outage and only during an ENS event. This limited energy methodology meets the two hour limitation of the RMRG but has a shortcoming in that it provides the two hours of generation support during the highest marginal energy cost hours. Given that high marginal energy costs typically occur during hours when system load is at it's highest, this means that the reliability contribution provided by the two hours of RMRG support is likely somewhat overstated in the PaR modeling To understand the potential magnitude by which the RMRG support might be overstated, a sensitivity was performed in which the RMRG units were excluded from the analysis. The results of this sensitivity showed the generation support provided by the RMRG acts to reduce the Planning Reserve Margin from approximately 17.8% to 16.3% or 1.5%. From this we can see that the limited energy methodology used to represent the RMRG support is likely to be a small factor in the overall reserve margin level required for the system (i.e., it is probably a small part of the 1.5% total impact of the RMRG support).

2.8 TRANSMISSION LIFELINE - NON PSCO IMPORTS

PSCo is interconnected with the Western Interconnect (WECC reliability council area) and expects that in an emergency situation it can utilize these interconnections to import additional power supplies into its system. The exact quantity of additional power supply is dependent on the availability of unused transmission capacity. PSCo estimates that it will have access to roughly 200 MW plus or minus 50 MW of unused transmission capacity during peak load periods. The reliability benefit of this transmission import capability was included in this analysis through the representation of an additional 200 MW of imports with Monte Carlo draws around plus or minus 50 MW.

Model runs were also performed without this 200 MW of import capability. These runs allowed PSCo to isolate the contribution that this 200 MW of import capability provides to the system through a reduction in the required planning reserve. As reported in Section 3 below, from this sensitivity run it was found that the existence the 200 MW Transmission LIFELINE allows reducing the Planning Reserve Margin from approximately 19.2% to 16.3% while maintaining the LOLP at 1-day-in-10-years.

2.9 USING A GENERIC GAS TURBINE AS A PROXY FOR INCREASING PLANNING RESERVES AT THE MARGIN

In order to perform this study, it was necessary to run the stochastic analysis at several different levels of planning reserve. For example if additional resources need to be added to the model in order to move the Planning Reserve Margin level from 10 percent to 12 percent and so on. The resource used to incrementally increase Planning Reserve Margin needs to be (a) highly reliable as a supply source and (b) relatively low cost to acquire since it will likely used at a very low capacity factor. While there are numerous supply technologies available for increasing supply, the reasonable supply unit to use for this purpose is a simple cycle GT.

2.10 DETERMINATION OF LOLP

The LOLP analysis methodology Ventyx applied in this study is a marked improvement over traditional methods for determining LOLP. Where, in the past, company's often computed an annual LOLP index as the summation of daily probabilities (often termed the "daily risks") over the entire year being studied, Ventyx computes LOLP based on a stochastic production cost model simulation where all relevant factors and uncertainties are included in the simulation. The analysis predicts both the probability of not serving a specific amount of load, and in addition provides insights into the dimension and amount of energy that would not be served—referred to as unserved energy or expected un-served energy (EUE). The Ventyx LOLP methodology calculates LOLP for each hour where the LOLP is the probability that available generation capacity in a given hour is less than the system load. The primary measurement used in accessing resource adequacy in this analysis is Loss of Load Hours (LOLH), which is typically used in the energy industry. Generally, if a utility's loss of load hours is not greater than or equals 1-day-in-10-years (or 2.4 hours in 1 year), it is seen as a reliable system. Unserved Energy (aka Energy Not Served…ENS) results in the model if on a particular hour the model is unable to find sufficient supply to meet the load plus the required operating reserve margin. If that happens on an hour, then this is counted as one LOLH. For LOLH counting purposes, there is a single LOLH if on an hour the load is not met. The counting is the same if the unserved load is 1 MW or if it is, for example, 200 MW. Given multiple iterations of the study year (with different Monte Carlo draws on loads and unit forced outages, etc), the metric used for this LOLP study is the average number of hours of LOLH over the 100 iterations. So if there are 99 iterations with zero LOLH and one iteration with 100 LOLH, then the expected (average) LOLH for the 100 iterations for this year is 1 LOLH. As indicated above, and average LOLH of 2.4 hours in the 1 year analysis is considered to be 24 LOLH hours in 10 years or 1 day in ten years.

For purposes of this study, Ventyx analysis looks for that Planning Reserve Margin level that will provide a 1-day-in-10-year LOLP.

2.10.1 Calculating The Planning Reserve Margin

A number of questions arise when the objective is calculating an accurate Planning Reserve Margin for a system. The common method of calculating Planning Reserve Margin is represented by the following equation:

$$\frac{[(\text{Resources} - \text{Peak Load}]}{(\text{Peak Load})}$$

Peak Load: Peak load is generally the needle peak load of the control area. In this study, where PSCo is modeled as a single zone, the peak hour for the entire system occurs in July.

Resources: The peak capacities of thermal and hydro stations that are in PSCo are included in the calculation except for Cabin Creek Pumped Storage which is counted at 210 MW. Wind capacity is counted at 12.5% of nameplate rating. Interruptible loads and demand side management programs are included as resources but for load and resource balance purposes, they are subtracted from the peak load.

Table 6
2013 PSCo Expected Reserve Margin

2013 L&R	MW	LOLH
Peak Load 50th percentile	7310	
interruptible loads	-401	
Firm Peak Obligation	**6909**	
Net Dependable Capacity from Table I above not including CT 129A and not including FSV CT	7410	
NET Planning Reserve Margin in 2013 without CT 129A	7.3%	
Needed Operating Reserves	5.7%	
Effective Starting Point Planning Reserve Margin	13.0%	69.8
Recommended Reserve Margin -- 1 day in 10 years	16.3%	24.0

The conclusion of this LOLH is that a 16.3% PRM is needed to provide a 1 day in 10 year LOLP. This level is determined by performing analysis that does not interrupt load until the operating reserve drops below zero

Table 7 in section 2.11 below reflects the loads and resources in the year 2013 for PSCo currently planned, but without the assumed generic CT 129A and without the new FSV CT units. This was the starting point for the LOLP analysis in this report. The generic CT 129A and FSV CT units were removed to assure that the starting analysis results in a LOLP that was greater than one-day-in-10 years. That staring point as indicated above resulted in a LOLH of 69.8 hours. A one-day-in-10 years would have an LOLH of 24.0 hours. To achieve that, Ventyx then started adding gas turbines until it found the level of Planning Reserve Margin that resulted in a LOLP of one-day-in-10 years

2.11 Analysis Starting Point Operating Reserve Margin

For year 2013, PSCo estimates it will be required to maintain approximately 419 MW of operating reserves as its portion of the RMRG reserve obligation. If operating reserves fall below 419 MW, PSCo would likely curtail load if it cannot arrange for additional power supplies. The PaR model used to perform this LOLP analysis, however, is not capable of curtailing load (i.e., registering unserved energy) and enforcing an operating reserve requirement. The model will only register unserved energy events in hours where the sum of all generation resources operating at their full capability is less than the load on the system and there is energy not served.

To account for this PaR model limitation, it is necessary to add "operating reserves" to the "planning reserve" level included in the model run that produces a 1-day-in-10-year level of reliability. Based on the 2013 peak load forecast of 7,310 MW, the 419 MW operating reserve requirement represents 5.73% (419 MW/7,310 MW = 0.0573) that must be added to the model results. As summarized in Section 3 below, the starting point for the PSCo Planning Reserve Margin analysis is a 13.0% starting reserve level that resulted in an LOLH of 69.8, which is 2.9-days-in-10-years (69.8 / 24 hours = 2.9 days) as shown in the table above. To determine an expected LOLP of 1-day-in-10-year LOLP, Ventyx added 210 MW of generic CT generation and found a LOLP of slightly higher than 1-day-in-10-years, or 26.9 hours. This level equates to a Planning Reserve Margin of 16%. Ventyx then added another 60 MW of CT capacity which is a Planning Reserve Margin of 17% and found a LOLP of less than 1-day-in-10-years, or 17.7 hours.

Interpolating between these two LOLP values determines a Planning Reserve Margin of 16.3% equates to a target 1-day-in-10-years LOLH of 24.0 hours. This interpolation to a one-day-in-10-years indicates PSCo's Planning Reserve Margin should be 16.3%.

3 ANALYSIS RESULTS

The goal of this LOLP analysis was to determine the Planning Reserve Margin for the PSCo system that would achieve an LOLP of 1 day in 10 years or, an Energy Not Served (LOLH) of 24 hours in 10 years (or 2.4 hours in one year). Table 7 contains a summary of the relationship between reserve margin and LOLH, both with and without 200 MW of transmission lifelines (i.e., transmission capacity held for use in accessing additional power supplies on short notice). All reserve margin values in Table 7 include the effects of operating reserve requirements.

Table 7
LOLP Results Summary

Reserve Margin (no transmission lifelines)	Reserve Margin (with 200 MW transmission lifeline)	LOLH (hrs in 10 Years)
16%	13%	69.8
18%	15%	39.6
19%	16%	26.9
20%	17%	17.7
22%	19%	7.9
24%	21%	1.8

Figure 3 below is an illustration of the LOLH / Energy Not Served values provided in Table 7 as a function of reserve margin level. By interpolation a reserve margin of 16.3% (with 200 MW transmission lifeline) yields 1-day in 10 years level of LOLH

Figure 3
Expected Hours of Energy Not Served