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PUBLIC SERVICE COMMISSION

Via Courier

April 23rd, 2013

Mr. Jeff Derouen, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

Re: Docket Case No. 2012-00578

Dear Mr. Derouen:

Enclosed for the filing are an original and ten copies of the *ALEXANDER DESHA, TOM VIERHELLER, BEVERLY MAY, AND THE SIERRA CLUB'S RESPONSE TO KENTUCKY POWER COMPANY'S DATA REQUESTS ATTACHMENTS FOR THE SAID FILING REGARDING DATA RESPONSE NO. 16* in docket 2012-00578 before the Kentucky Public Service Commission. Please note that these additional attachments were included in the certificate of service copies sent to other parties. This filing contains no confidential information.

Sincerely,

Ruben Mojica
Sierra Club Environmental Law Program
85 2nd Street, 2nd Floor
San Francisco CA, 94105
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ATTACHMENTS

SC Responses to

KPC-16

TENNESSEE VALLEY AUTHORITY POTENTIAL STUDY

VOLUME 1: EXECUTIVE SUMMARY

Final Report

Report Number 1360

December 21, 2011

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An EnerNOC Company

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CHAPTER 1

INTRODUCTION

Background

The Tennessee Valley Authority (TVA) has contracted with Global Energy Partners (Global) to conduct a potential study to assess 20-year potentials for energy efficiency (EE) and demand response (DR). TVA has an aspirational goal to lead the southeast in energy efficiency, and believes this leadership can be accomplished through the development and implementation of action plans for EE, DR, and end-use generation. This potential study will provide information to assist TVA in meeting that goal.

Toward this end, Global conducted a detailed, bottom-up assessment of the TVA market to deliver forecasts of energy use and peak demand, as well as forecasts of energy and peak-demand savings achievable through energy efficiency and demand response programs. The 20-year potentials study addresses the residential, small commercial, large commercial, and industrial sectors. Results of this task are discussed in two volumes, one for energy efficiency and one for demand response, as described below in the report organization.

Global also compared the results of the potential savings to those from existing regional potential studies that are specific to the Southeast and other select studies. This analysis, which appears in both the energy efficiency and demand response reports, also compares these potential studies with regard to methodology, assumptions, approaches, estimated baselines, technical performance, adoption, and program/regulatory context.

This document is **Volume 1: Executive Summary,** an overview of the entire energy efficiency and demand response analysis. The other volumes are:

- Volume 2, Energy Efficiency Potential
- Volume 3, Demand Response Potential

Objectives

Key objectives for the study include:

- Conduct a 20-year bottom-up energy efficiency potential study to determine the potential for specific energy efficiency measures to reduce the consumption and peak demand of electricity in the TVA service territory.
- Conduct a demand response potential study to determine the potential for reduction in peak demand through demand response programs.
- Compare the potential study results with other national and regional studies, including details regarding assumptions used to develop each of the studies.

Definitions of Potential

In this study, we estimate the potential for energy efficiency savings. The savings estimates represent gross savings[1] developed into three types of potential: technical potential, economic potential, and achievable potential. Technical and economic potential are both theoretical limits to efficiency savings. Achievable potential embodies a set of assumptions about the decisions

[1] Savings in "gross" terms instead of "net" terms means that the baseline forecast does not include naturally occurring efficiency. In other words, the baseline assumes that energy efficiency levels remain fixed as they are today. This rule holds true except in cases where enactment of future codes and standards were on the books before January 2011, e.g., the effects of the EISA 2007 lighting efficiency standard.

consumers make regarding the efficiency of the equipment they purchase, the maintenance activities they undertake, the controls they use for energy-consuming equipment, and the elements of building construction. For this reason, we developed a range of achievable potential. These levels are described below.

Technical potential is defined as the theoretical upper limit of energy efficiency potential. It assumes that customers adopt all feasible measures regardless of their cost. At the time of equipment failure, customers replace their equipment with the most efficient option available. In new construction, customers and developers also choose the most efficient equipment option. Examples of measures that make up technical potential in the residential sector include:

- Ductless mini-split air conditioners with variable refrigerant flow
- Ground source (or geothermal) heat pumps
- LED lighting

Technical potential also assumes the adoption of every available other measure, where applicable. For example, it includes installation of high-efficiency windows in all new construction opportunities and air conditioner maintenance in all existing buildings with central and room air conditioning. The retrofit measures are phased in over a number of years, which is longer for higher-cost measures.

Economic potential represents the adoption of all ***cost-effective*** energy efficiency measures. In this analysis, the total resource cost (TRC) test, which compares lifetime energy and capacity benefits to the incremental cost of the measure, is applied. Economic potential assumes that customers purchase the most cost-effective option at the time of equipment failure and also adopt every other cost-effective and applicable measure.

Achievable - High potential takes into account expected program participation resulting from ideal implementation conditions and customer preferences for energy-efficient technologies and demand response programs. Achievable - High establishes a maximum target for the EE savings that a utility can hope to achieve through its EE programs and involves incentives that represent a substantial portion of the incremental cost combined with high administrative and marketing costs.

Achievable - Low potential represents a lower bound on Achievable potential. It reflects limited DSM budgets and significant barriers to customer acceptance.

CHAPTER 2

ENERGY EFFICIENCY POTENTIAL

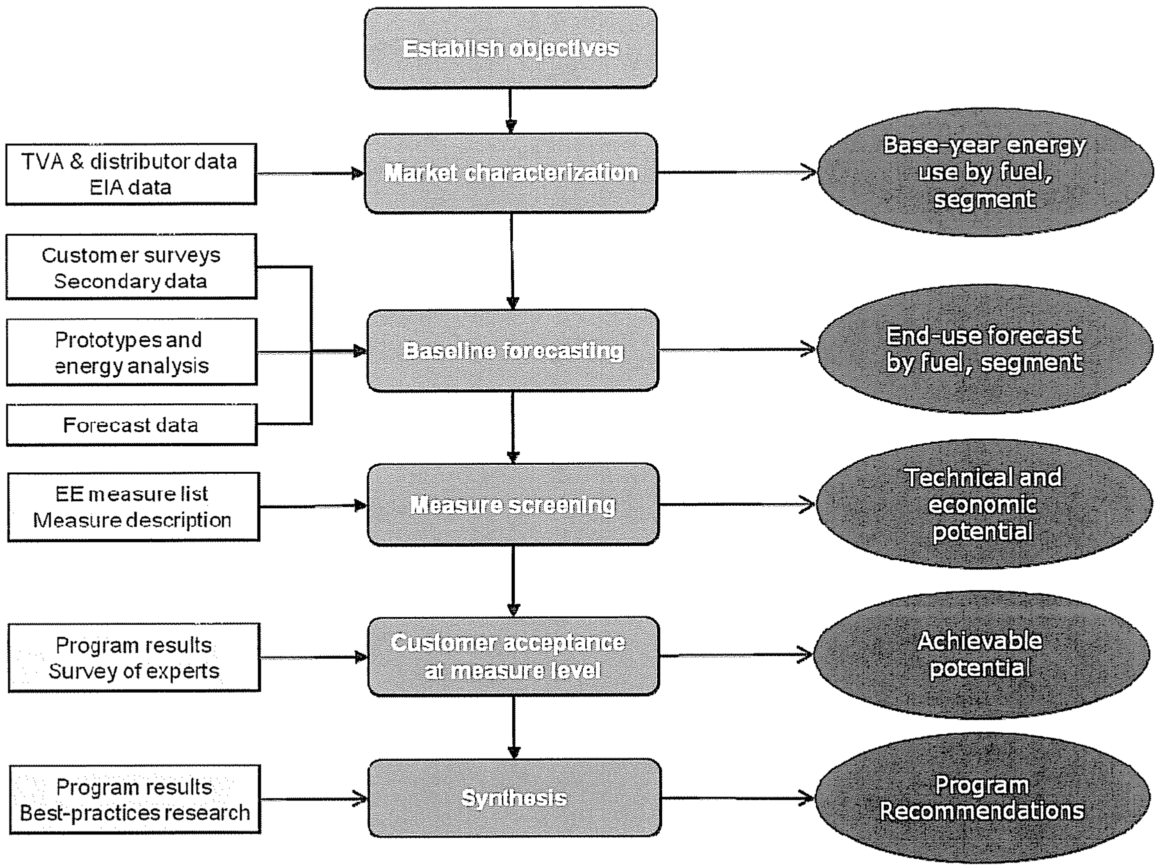
Analysis Approach

To perform the energy efficiency analysis, Global used a bottom-up analysis approach as shown in Figure 2-1. We took the following steps:

1. Held a meeting with the project team to refine the objectives that were identified in the TVA RFP. This resulted in a work plan for the study.
2. Performed a market characterization to describe sector-level electricity use for the residential, commercial, and industrial sectors for the base year, TVA 2009. (Note that all years referred to in this report are TVA fiscal years). This included using utility data and secondary data from sources such as the American Community Survey (ACS) and the Energy Information Administration (EIA).
3. Utilized TVA primary market research (such as TVA's 2010 residential market saturation survey) and secondary sources to understand how customers in the Tennessee Valley currently use electricity. Combining this information with the market characterization, we developed energy market profiles that describe energy use by sector, segment, and end use for 2009.
4. Developed a baseline electricity forecast by sector, segment, and end use for 2012 through 2032. Results presented in this volume are through 2030.
5. Identified and analyzed energy-efficiency measures appropriate for the Valley.
6. Estimated four levels of energy-efficiency potential, *Technical, Economic, Achievable - High,* and *Achievable - Low.*
7. Reviewed the current programs offered by TVA in light of the study findings to make strategic program recommendations for achieving savings.

The results from these steps are presented in the remainder of this chapter. Details are provided in Volume 2.

Figure 2-1 Overview of Analysis Approach



Market Characterization

The Tennessee Valley Authority (TVA) is the largest electric utility in the U.S. on the basis of energy sales, with annual sales of 174 billion kWh in 2010.[2] TVA serves as the wholesale provider for 155 power distributors and directly serves 59 industrial and federal facilities. Its service territory, with an approximate area of 80,000 square miles, encompasses more than 9 million people in seven southeastern states. It includes nearly the entire state of Tennessee as well as portions of Alabama, Georgia, Kentucky, Mississippi, North Carolina, and Virginia. Major cities are Memphis, Nashville, Knoxville, Huntsville, and Chattanooga. The top industries in the service territory are chemical products, primary metals, paper products, and food products.

Total electricity use for the residential, commercial and industrial sectors for TVA in 2009 was 146,118 GWh.[3] As shown in Figure 2-2, the largest sector is residential, accounting for 42%, or 62,246 GWh. The remaining use is split between the commercial and industrial sectors, at 39,561 GWh and 44,311 GWh respectively.

[2] http://www.tva.com/abouttva/index.htm

[3] Energy given "at-the-meter," i.e., does not include line losses. Also, totals do not include outdoor lighting, federal customers, or a small number of DSI customers as specified by TVA project management.

Figure 2-2 Sector-Level Electricity Use, 2009

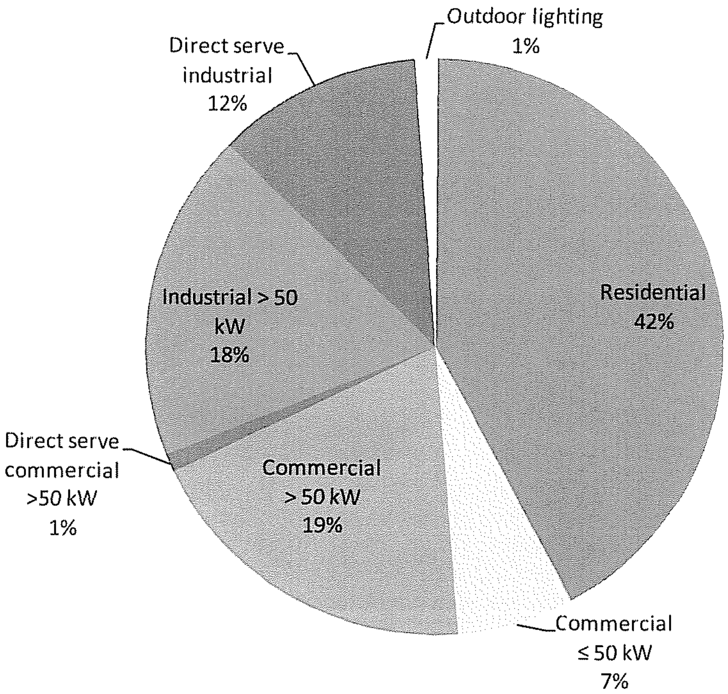


Figure 2-3 presents the end-use shares of residential electricity use for each housing type. Here, the single family segment is shown as a segment average as well as broken out into single family all-electric homes and single family other homes. The TVA territory has a large number of all-electric homes, roughly half of the single family homes in the Valley, with comparatively larger consumption in heating, water heating, and cooking.

Figure 2-3 End-Use Shares of Total Electricity Use by Housing Type, 2009

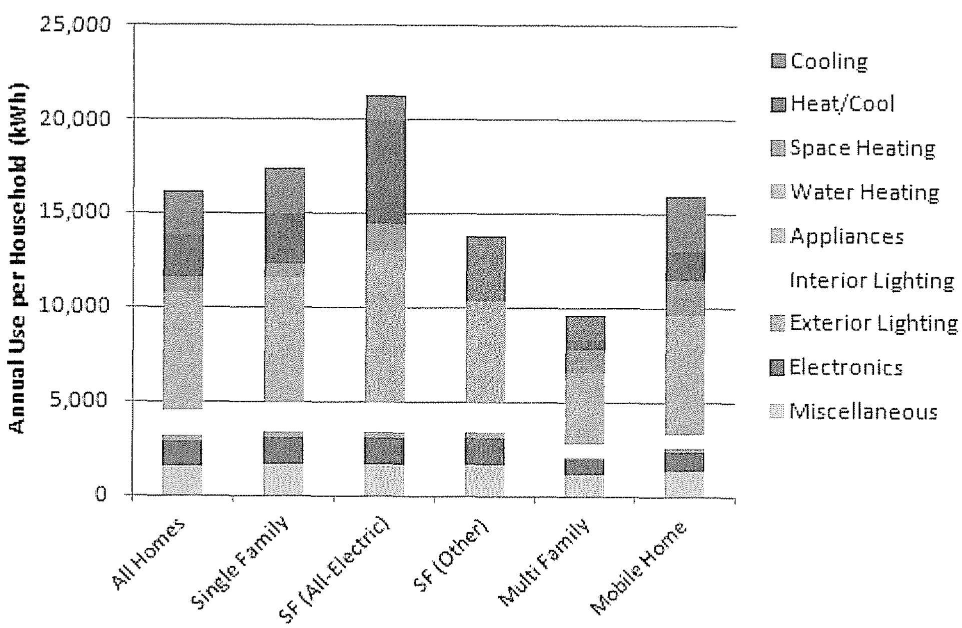


Figure 2-4 shows the breakdown of annual commercial electricity usage by end use. Cooling and lighting are the largest end uses in the commercial sector, accounting for over half of total usage.

Refrigeration and ventilation are the next largest end uses. Each of the remaining end uses accounts for 5% or less of total usage.

Figure 2-4 Commercial Electricity Consumption by End Use, 2009

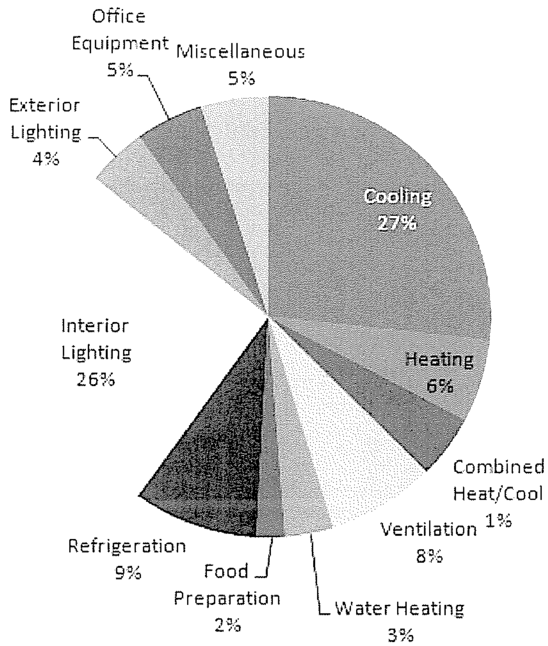
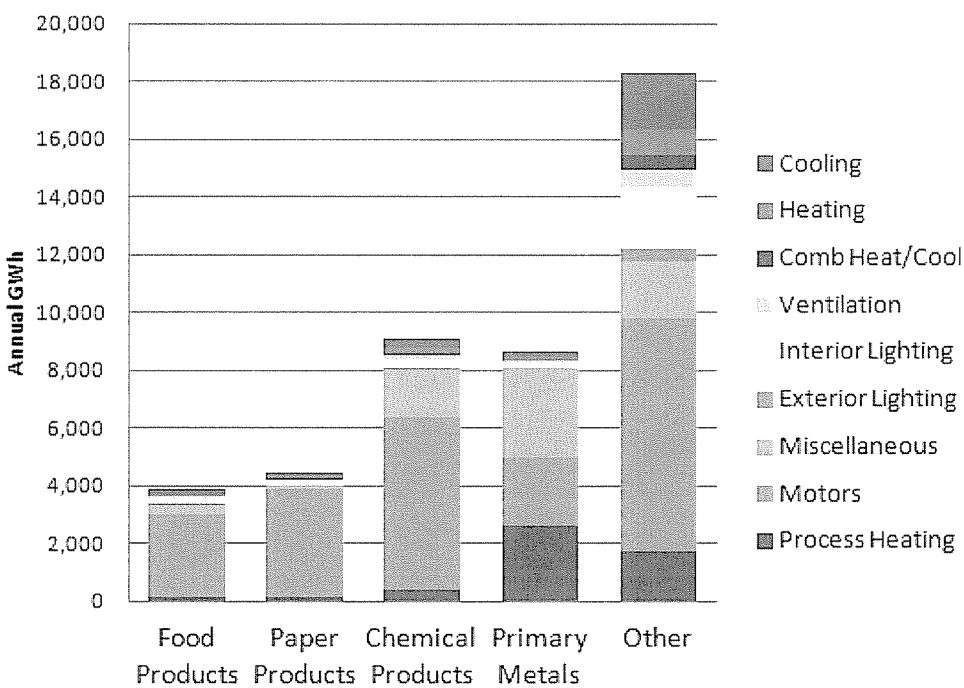


Figure 2-5 shows how the major industrial segments in the Valley used electricity in 2009. Machine drives dominate all segments, though process heating is more prevalent in the primary metals segment.

Figure 2-5 Industrial Electricity Use by End Use and Segment, 2009



Baseline Forecast

Prior to developing estimates of energy-efficiency potential, a baseline end-use forecast was developed to quantify how electricity is used by end use in the base year and what the consumption is likely to be in the future in absence of new utility programs and naturally occurring efficiency. The baseline forecast serves as the metric against which energy efficiency potentials; technical, economic, and achievable, are measured. The baseline forecast we developed for TVA was consistent with its official forecast from October 2011.

Figure 2-6 through Figure 2-8 present the baseline end-use forecasts for the residential, commercial and industrial sectors. Referring to Table 2-1 and Figure 2-9, electricity use across all three sectors is expected to increase by 24% between the base year, 2009, and 2030, for an average annual growth rate of 1.0%.

- The residential sector has the highest growth, with a 33% increase (1.4% annual growth rate) over the forecast horizon.
- The commercial sector has a dip in the short term and then recovers after 2015. Overall, it has the slowest growth at 0.6% per year on average.
- The industrial sector shows a steady increase in use throughout the forecast period with an average growth rate of 0.9% per year.

Figure 2-6 Residential Baseline Forecast by End Use

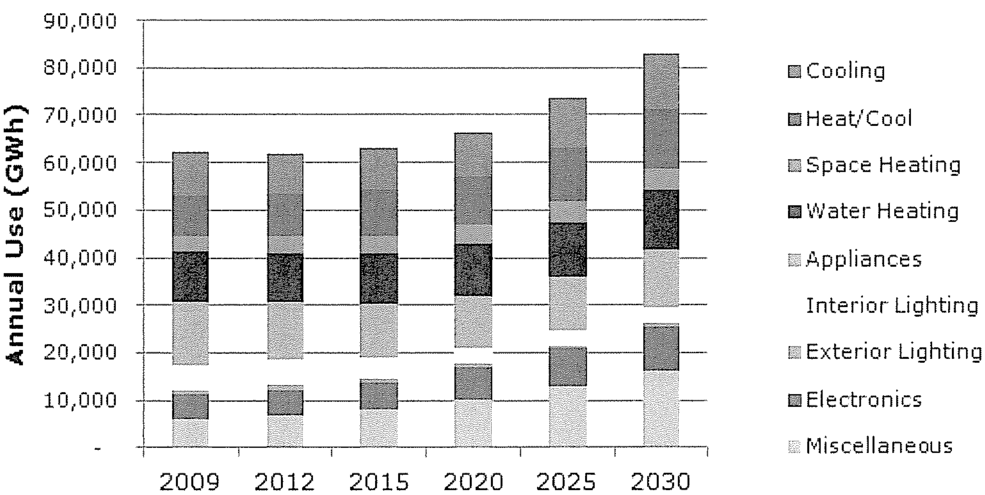


Figure 2-7 Commercial Baseline Electricity Forecast by End Use

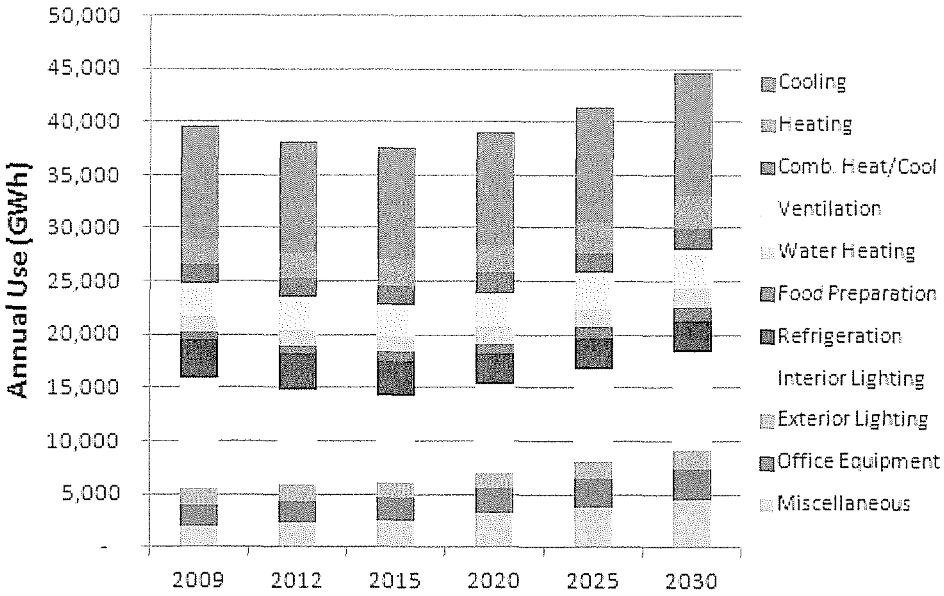


Figure 2-8 Industrial Baseline Electricity Forecast by End Use

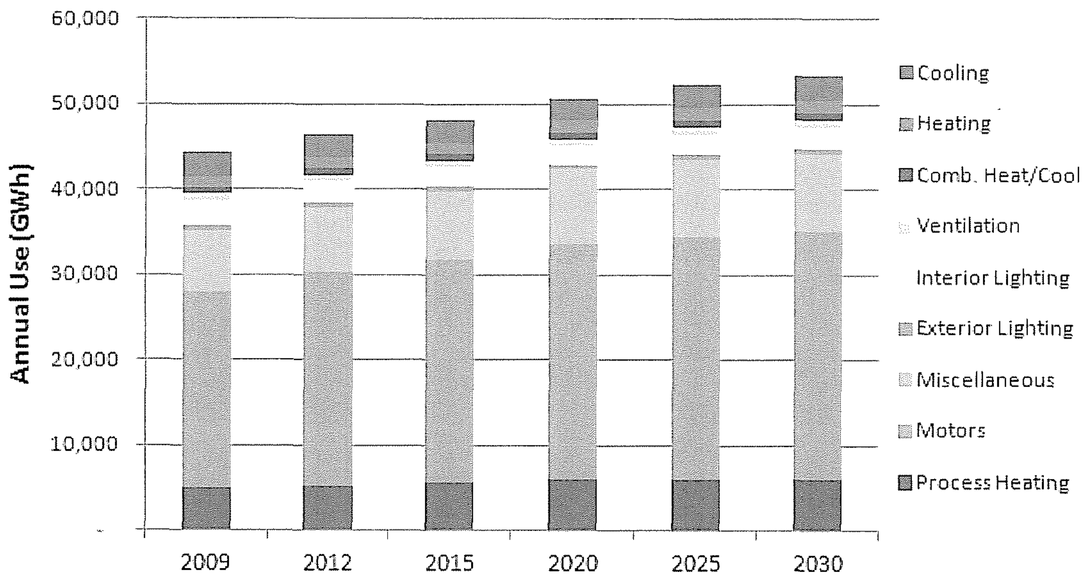
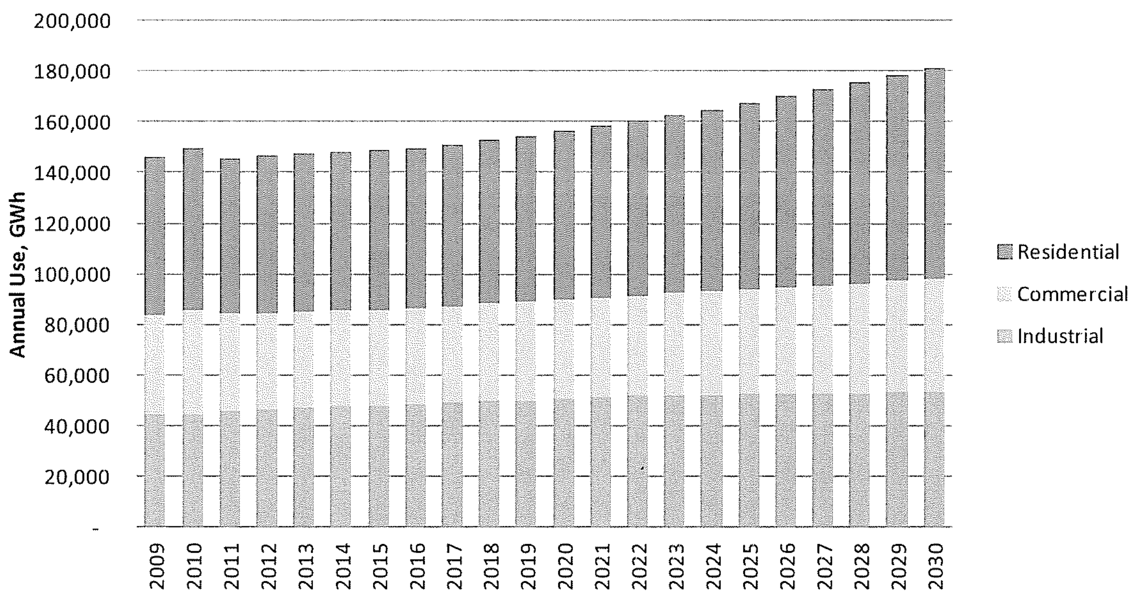


Table 2-1 Baseline Forecast Summary

Sector	2009	2012	2015	2020	2025	2030	% Change	Avg. growth rate
Residential	62,246	61,936	62,932	66,440	73,613	82,830	33%	1.4%
Commercial	39,561	38,176	37,587	39,026	41,485	44,718	13%	0.6%
Industrial	44,311	46,394	48,173	50,777	52,364	53,412	21%	0.9%
Total	**146,118**	**146,505**	**148,692**	**156,243**	**167,462**	**180,959**	**24%**	**1.0%**

Figure 2-9 Baseline Forecast Summary



Energy Efficiency Measures

The first step of the energy efficiency measure analysis was to identify the list of all relevant energy efficiency measures that should be considered for the TVA potential assessment. Sources for the measure assumptions were drawn from TVA's Measurement Manual and latest program evaluation results, Global's building modeling tool BEST, and Global's other measure databases from previous studies and program work.

The measures are categorized into two types according to the LoadMAP[4] taxonomy: equipment measures and non-equipment measures:

- *Equipment measures,* or efficient energy-consuming pieces of equipment, save energy by providing the same service with a lower energy requirement. An example is the replacement of a standard efficiency refrigerator with an ENERGY STAR model. For equipment measures, many efficiency levels are available for a specific technology that range from the baseline unit (often determined by code or standard) up to the most efficient product commercially available. For instance, in the case of central air conditioners, this list begins with the federal standard SEER 13 unit and spans a broad spectrum of efficiency, with the highest efficiency level represented by a SEER 21 unit.
- *Non-equipment measures* save energy by reducing the need for delivered energy but do not involve replacement or purchase of major end-use equipment (such as a refrigerator or air conditioner). An example would be a programmable thermostat that is pre-set to run the air conditioner only when people are home. Non-equipment measures fall into one of the following categories:
    - Building shell (windows, insulation, roofing material)
    - Equipment controls (thermostat, occupancy sensors)
    - Equipment maintenance (cleaning filters, changing setpoints)
    - Whole-building design (natural ventilation, passive solar lighting)
    - Lighting retrofits (included as a non-equipment measure because retrofits are performed prior to the equipment's normal end of life)

[4] Global's Load Management Analysis and Planning™ tool

- Displacement measures (ceiling fan to reduce use of central air conditioners)
- Commissioning and retrocommissioning

Table 2-2 summarizes the number of equipment and non-equipment measures evaluated for each sector.

Table 2-2 Number of Measures Evaluated

	Residential	Commercial	Industrial	Total Number of Measures
Equipment Measures Evaluated	102	126	85	**313**
Non-Equipment Measures Evaluated	42	52	74	**168**
Total Measures Evaluated	**144**	**178**	**159**	**481**

Energy Efficiency Potential Results

Table 2-3 and Figure 2-10 summarize the energy-efficiency savings for the different levels of potential relative to the baseline forecast. Figure 2-11 displays the energy-efficiency forecasts.

- *Achievable - Low potential* forms a lower point on the range of achievable potential. Across all sectors, this metric is 3,256 GWh in 2015 and increases to 19,093 by 2030. This represents 2.2% of the baseline forecast in 2015 and 10.6% in 2030. By 2030, Achievable – Low offsets 55% of the growth in the baseline forecast.
- *Achievable - High potential* forms the upper bound on the range of achievable potential. It is 7,494 GWh in 2015, which represents 5.0% of the baseline forecast. By 2030, the cumulative savings are 35,781 GWh, 19.8% of the baseline forecast, for an annual average of just over 1% per year. By 2030, Achievable – High completely offsets growth in the baseline forecast.
- *Economic potential*, which reflects the savings when all cost-effective measures are taken, is 12,418 GWh in 2015. This represents 8.4% of the baseline energy forecast. By 2030, economic potential reaches 44,821 GWh, 24.8% of the baseline energy forecast.
- *Technical potential*, which reflects the adoption of all energy efficiency measures regardless of cost-effectiveness, is a theoretical upper bound on savings. In 2015, energy savings are 15,347 GWh, or 10.3% of the baseline energy forecast. By 2030, technical potential reaches 57,244 GWh, 31.6% of the baseline energy forecast.

Table 2-3 Summary of Energy Efficiency Potential

	2012	2015	2020	2025	2030
Baseline Forecast (GWh)	146,505	148,692	156,243	167,462	180,959
Energy Savings (Cumulative GWh)					
Achievable - Low	811	3,256	7,963	13,420	19,093
Achievable - High	2,417	7,494	15,337	25,215	35,781
Economic	4,481	12,418	21,658	33,091	44,821
Technical	5,349	15,347	27,545	42,822	57,244
Energy Savings (% of Baseline)					
Achievable - Low	0.6%	2.2%	5.1%	8.0%	10.6%
Achievable - High	1.7%	5.0%	9.8%	15.1%	19.8%
Economic	3.1%	8.4%	13.9%	19.8%	24.8%
Technical	3.7%	10.3%	17.6%	25.6%	31.6%

Figure 2-10 Summary of Achievable Potential Energy Savings

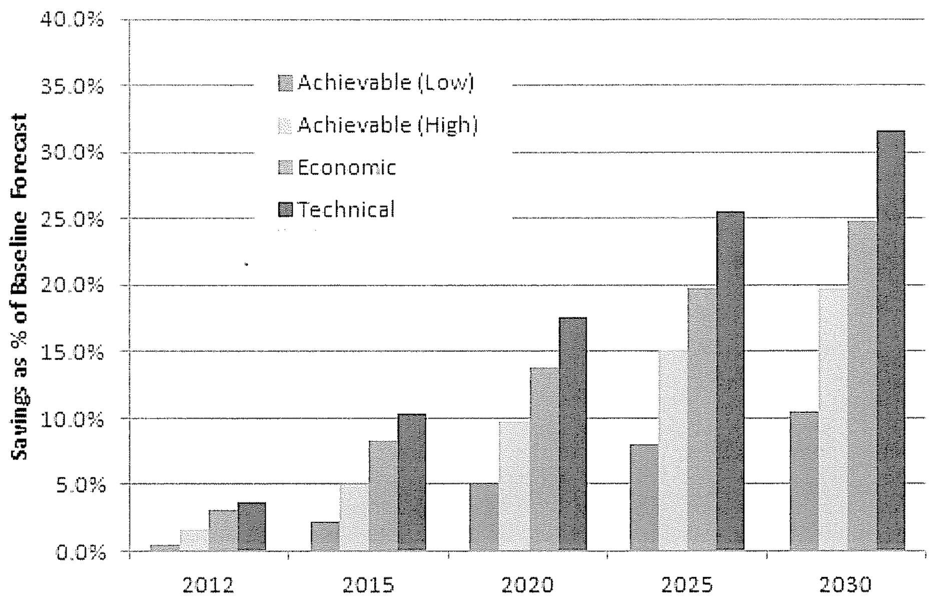


Figure 2-11 Energy Efficiency Potential Energy Forecasts (GWh)

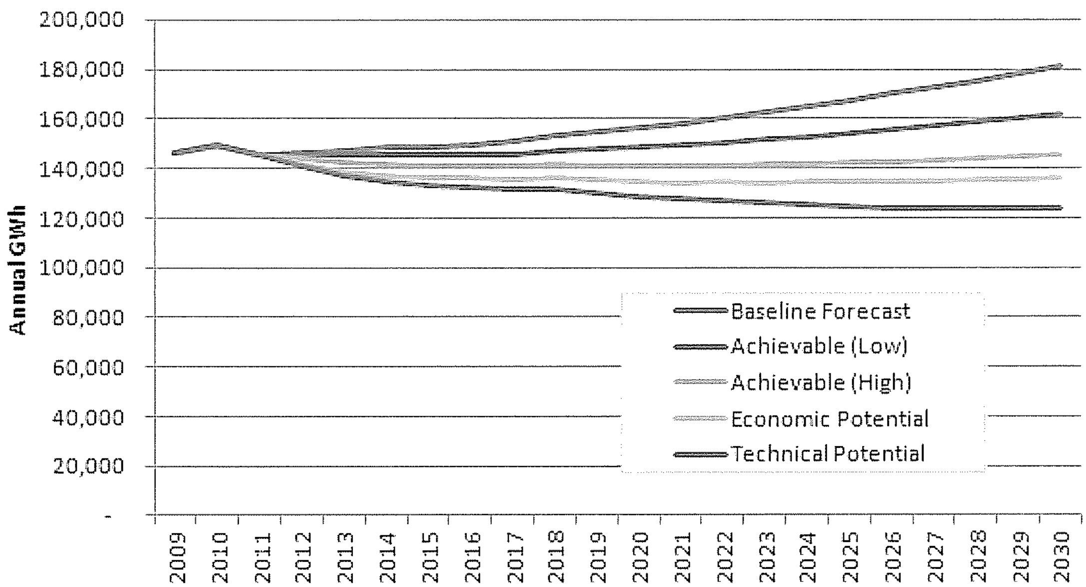


Table 2-4 summarizes the range of achievable potential by sector. The residential sector accounts for the largest portion of the savings, about half of the Achievable - Low potential, followed by the commercial and then the industrial sectors.

Table 2-4 Achievable Energy Efficiency Potential by Sector (GWh)

	2012	2015	2020	2025	2030
Achievable - Low Savings (GWh)					
Residential	384	1,444	3,216	5,652	8,307
Commercial	228	985	2,613	4,163	5,557
Industrial	199	826	2,134	3,604	5,229
Total	**811**	**3,256**	**7,963**	**13,420**	**19,093**
Achievable - High Savings (GWh)					
Residential	1,107	3,356	6,445	10,961	15,759
Commercial	660	2,181	4,693	7,419	10,130
Industrial	651	1,957	4,199	6,835	9,892
Total	**2,417**	**7,494**	**15,337**	**25,215**	**35,781**

Figure 2-12 focuses on the range of residential achievable potential in 2015 and 2030.

- Lighting equipment replacement accounts for the highest portion of the savings in the near term as a result of the efficiency gap between advanced incandescent lamps and CFL lamps.
- Water heating accounts for large savings in the long term because heat pump water heaters are found to be cost-effective.
- Electronics, appliances, and space conditioning measures also contribute significantly to the savings.

Figure 2-12 Residential Achievable Potential by End Use in 2015 and 2030

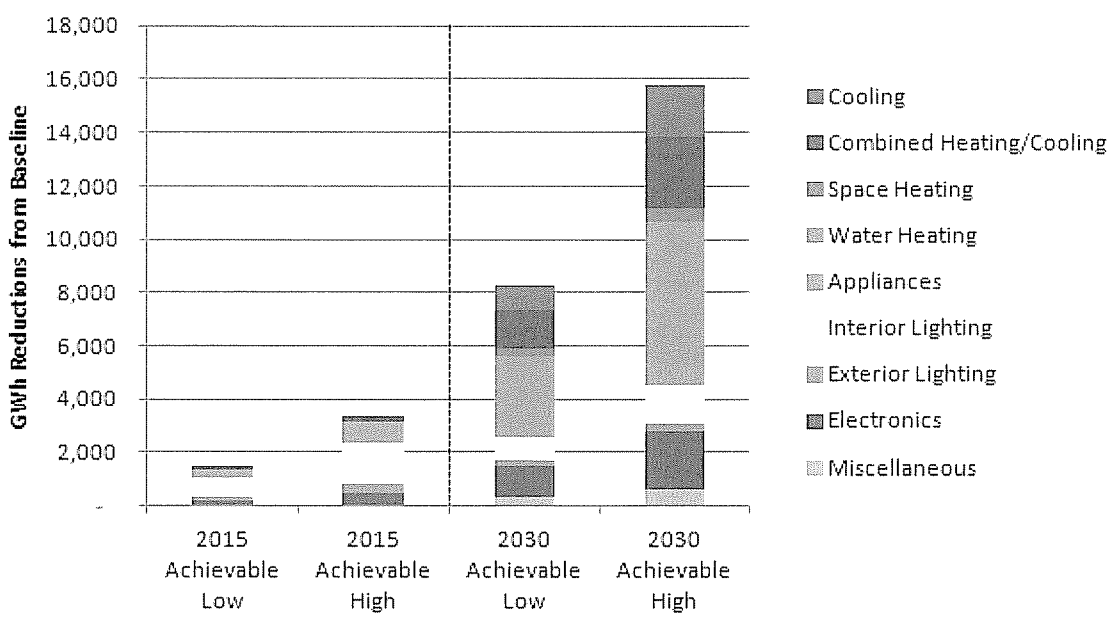


Figure 2-13 compares the range of potential in 2015 and 2030 for the commercial sector. Not surprisingly, interior lighting delivers the highest achievable savings throughout the study period. In 2015, exterior lighting is second, office equipment is third, and ventilation and cooling are next highest in terms of Achievable - Low potential. In 2030, though interior lighting still provides the greatest Achievable - Low potential, cooling is the second greatest source of savings, followed by refrigeration and exterior lighting.

Figure 2-13 Commercial Achievable Potential Savings by End Use in 2015 and 2030

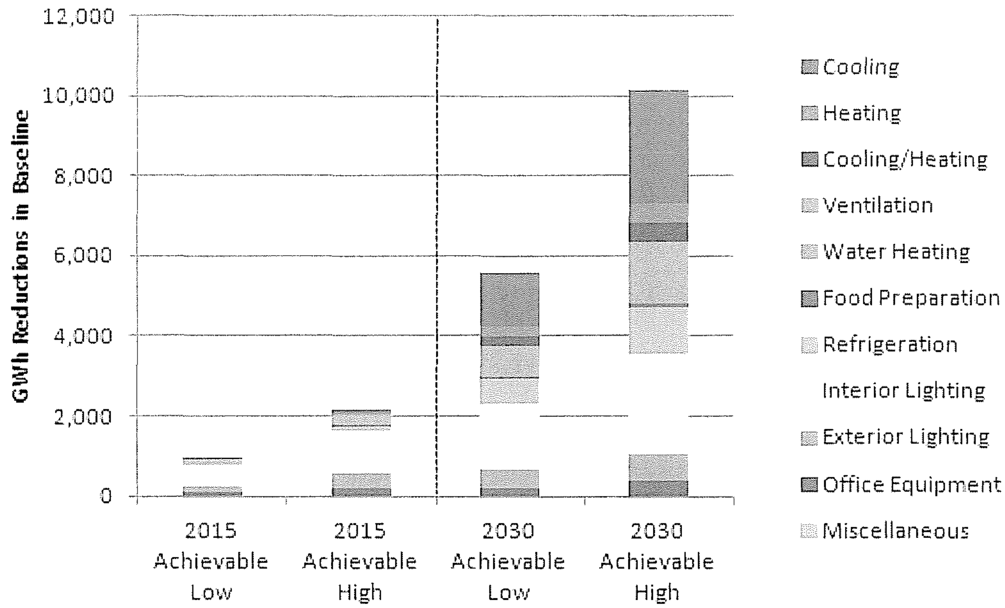
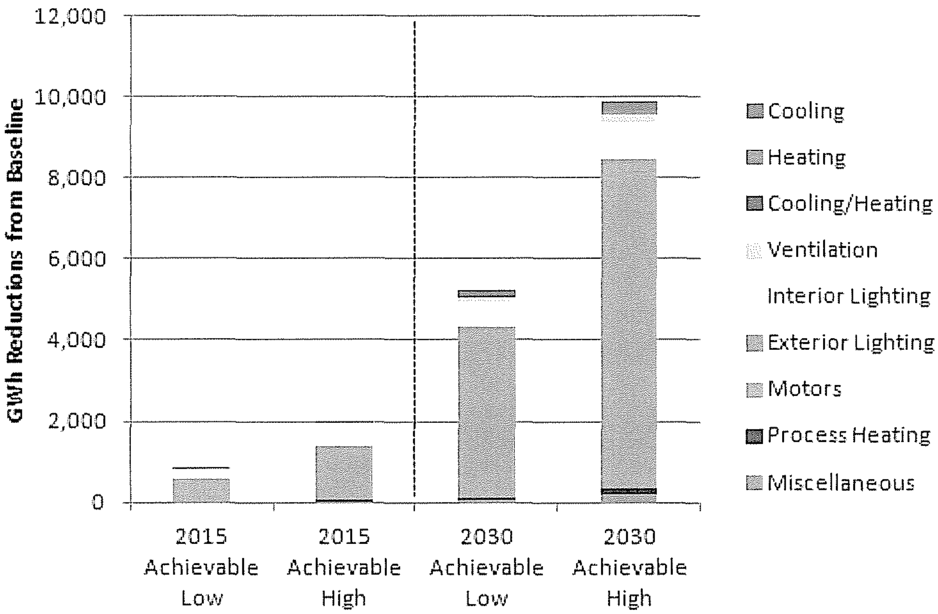


Figure 2-14 illustrates the range of achievable potential savings by end use in 2015 and 2030 for the industrial sector, reinforcing the dominance of the machine drive (motors) category. The specific measures that account for the largest savings in the industrial segment are:

- Integrated plant energy management: 45 MWh and 392 MWh of Achievable – Low potential in 2015 and 2030 respectively
- Fan and pump system measures, which include system optimization, energy management, and equipment upgrades: 135 GWh and 1,425 GWh of Achievable – Low potential in 2015 and 2030 respectively

Figure 2-14 Industrial Achievable Potential Savings by End Use in 2015 and 2030



EE Program Recommendations

The results of the EE assessment reveal that TVA has significant potential for energy efficiency resources over the next two decades. Our analysis has shown that TVA can realize an achievable range of reductions between 10.4% and 19.4% of the baseline forecast in 2030 with the measures represented in this report.

TVA's energy-efficiency programs are off to a strong start, with a comprehensive suite of programs currently moving from the planning phase to the implementation phase. Based on this study, Global provides the following recommendations to preserve and augment that momentum.

General Recommendations

- ***Coordinate distributor layer between TVA and end-user:*** As a wholesale provider for 155 power distributors, TVA's business landscape poses unique challenges for the administration of energy efficiency programs. Because of this arm's-length relationship with end users, TVA does not have the same level of information about customers as other utilities. TVA will need to coordinate closely with its power distributors. To facilitate better coordination, TVA should consider the hiring and training of dedicated personnel to serve as liaisons with the distributors.
- ***Maintain transparent stakeholder process:*** To date, TVA has been transparent and aboveboard with internal and external stakeholders. Continuing to involve stakeholders and cultivating a mutual understanding of continuous improvement is of paramount importance to the future success of programs. We recommend an open and transparent stakeholder process with regular touchpoints and workshops. Suggested workshop topics are: technical resource manual with deemed measure databases; evaluation, measurement, and verification protocols; emerging technologies; innovative program strategies; periodic reviews of program results; and sharing success stories from individual power distributors or customers.
- ***Create internal EE targets:*** TVA should continue to evolve and formulate its specific objectives regarding energy efficiency by creating targets and goals. Global recommends targets that fall within the range of achievable potentials identified in this study.
- ***Aggressively pursue lighting savings in the near-term:*** Lighting represents a bulk of the low-hanging fruit in the near term, with significant untapped potential in all sectors. Programs have not yet aggressively targeted lighting, beyond a limited CFL giveaway effort. Working upstream with trade allies and retailers will likely yield significant savings. In particular, as the EISA standards take effect, educational programs and coordination with retailers can help customers move beyond EISA-compliant lamps to more efficient CFL and LED technologies.
- ***Create targeted marketing messages:*** Energy prices in the Valley are cheaper than the national average. Correspondingly, the customer base does not have a long history of exposure to marketing and education regarding energy and sustainability issues like other jurisdictions around the nation. As a result, customers have not been strongly driven to consider energy efficiency measures, and awareness and adoption will be lower than national averages at first. Targeted marketing and education efforts should be developed with messages that speak to the customer base and cultivate shared attitudes.
- ***Expand knowledge of the customer base:*** TVA's pre-existing data regarding the customer base is minimal. Opportunities should be explored to expand this knowledge base. Not only will this information be valuable for program efforts, the results can be shared with distributors, many of whom are too small to conduct surveys on their own. Surveys should collect data in all sectors on end use equipment saturations, customer attitudes, and measure penetration.

Residential Recommendations

- ***Pursue CFLs:*** Significant, cost-effective potential is available with CFLs, in spite of the forthcoming EISA standards that will reduce their per-unit savings compared to the new baseline. Also, TVA should focus strong attention on specialty CFL programs, as these bulbs are not addressed in the EISA standard.
- ***Focus on all-electric homes:*** The prominence of all-electric homes, roughly 50%, has many implications for program design. Audit programs with direct install measures are one mechanism for reaching these customers. New construction incentives can help to boost the penetration of heat pumps, heat pump water heaters (HPWH), and advanced construction designs.
- ***Pursue heat pump water heaters:*** Heat pump water heaters offer significant potential, but educational efforts, for trade allies as well as homeowners, will be required to achieve this potential. Consider bundling HPWH with the existing and established space conditioning heat pump program to take advantage of the gains the heat pump programs have made in acquainting trade allies and targeted participants with heat pump technology.

Commercial and Industrial Recommendations

- ***Pursue lighting savings:*** Strongly pursue lighting savings to accelerate the phase out of T12 fluorescent lighting. In particular, program efforts can help intercept building operators before they make purchase and stocking decisions that could lead to the hoarding of T12 lamps.
- ***Create customized, multi-year plans for large, complex customers*:** For large enough customers, large success can be obtained with strategic energy management (SEM)[5] initiatives over longer time horizons. This means a larger tracking and time commitment, but many jurisdictions are finding this to be a more effective method than a "one and done" installation and rebate approach. These relationships involve personalized plans, identification of metrics, goal-setting, technical assistance, and attention from account executives.
- ***Focus program efforts on motor controls and system optimizations:*** Low-cost retrofits can have significant, low-cost energy impacts with minimal disruption (and often times improvement) of business processes.

[5] Sometimes called Continuous Energy Improvement (CEI).

CHAPTER 3

DEMAND RESPONSE POTENTIAL

Analysis Approach

The analysis approach for estimating demand response potential is, by necessity, different from the approach used for energy efficiency. Energy efficiency can occur outside of utility programs to the extent that it is naturally occurring or technology driven; but can be enhanced and enabled by utility programs. Demand response, however, does not exist without a utility program. A program-by-program analysis is therefore at the core of a demand-response potential study. The basic steps used to perform this assessment are as follows:

1. *Characterize the market.* The first step is to segment the market into the relevant customer segments. The first level of segmentation is by sector: residential and C&I customers. Within residential customers, we further segment the population by describing housing types and presence of end uses (such as single family homes with central air conditioning (CAC) and electric water heating). For C&I customers, the next level of segmentation is based on the maximum demand values, typically following utility rate schedules.
2. *Identify baseline forecast.* The second step is to identify what the peak demand forecast will be, absent any DR programs, for both summer and winter in the TVA service territory.
3. *Define relevant DR options.* The next step is to identify applicable DR options for each customer segment. DR options include direct load control (DLC), curtailable, demand reduction, capacity reduction, load shifting, pricing, and voltage reduction programs. Each of these options is mapped to the applicable customer segments. For some options, such as DLC, specific end uses can be controlled and they are identified. Also, enabling technologies, such as programmable communicating thermostats (PCT) are identified by customer segment.
4. *Outline DR program participation hierarchy.* For each customer segment that has more than one DR option, the next step is to define the participation hierarchy. This accounts for program overlaps and ensures that cross-participation in DR events and double counting does not take place.
5. *Develop program parameters.* Program parameters include participation rates, number of participants equipped with enabling technology, unit load reduction impacts, attrition rates, and DR event participation rates. Cost data are also developed for the analysis, including program development costs, customer marketing and recruitment costs, technology costs, customer incentives, operation and maintenance (O&M) costs, and program administrative costs.
6. *Estimate preliminary potential and assess cost-effectiveness.* The final step is to estimate the load reduction potential associated with each of the DR options by customer segment, and also at the aggregate level across programs and segment. Utility-provided avoided capacity costs are used to assess benefits from DR programs
7. *Develop estimates of achievable potential.* The final step is to estimate the load reduction potential associated with each of the DR options by customer segment, and also at the aggregate level across programs and segment. Achievable potential takes into account expected participation rates as well as cost-effectiveness of the program. For this study, we estimate a range of achievable potential:

- Achievable – High assumes higher participation rates that result from application of industry best practices in program design, higher budget limits for implementation, and does not incorporate the results of the cost effectiveness screen. Therefore, Achievable – High represents the upper bound of savings, regardless of cost.
- Achievable – Low assumes lower levels of participation as a result of limited budgets for program implementation and includes only those programs that pass the cost-effectiveness screen. Therefore the Achievable – Low represents a more realistic picture of DR potential given barriers to participation and cost constraints.

Unlike the energy-efficiency analysis, we do not consider technical or economic potential for demand response.

Matrix of Demand Response Options

For this study, a broad set of demand response options that combines traditional and emerging approaches was identified. They fall into eight groups: direct load control programs, curtailable programs, demand and capacity reduction programs, dynamic pricing programs, aggregator managed programs, load shifting programs, voltage regulation programs, and fast-DR. Table 3-1 translates the eight groups into eleven specific options by customer segment and identifies the enabling technology options and targeted end uses for each.

Table 3-1 Relevant DR Options Matrix

Demand Response Option	Brief Description	Eligible Customer Segments	Targeted End Uses
Residential Direct Load Control	Traditional DLC program utilizing either load control switches or programmable thermostats	Single Family residential customers with CAC, Water Heating, or Space Heating	CAC, Water Heating, Space Heating
C&I Direct Load Control	Traditional DLC program utilizing either load control switches or programmable thermostats	Small C&I customers with CAC, Water Heating, or Space Heating	CAC, Water Heating, Space Heating
Capacity Reduction	Voluntary load nomination program with capacity credits and energy credits	Small C&I, Medium C&I, Large C&I, Extra Large C&I (except 5&60 MR, > 500kW), Direct Serve	Customer Specific
Demand Reduction	Voluntary load nomination program with energy credits	Extra Large C&I, Direct Serve	Customer Specific
Curtailable	Contractual commitment to reduce load to a pre-specified level; capacity credits and non-performance provisions apply	Extra Large C&I, Direct Serve	Customer Specific
Dynamic Pricing	Voluntary time-variant pricing tariff (i.e., CPP)	Residential, Small C&I, Medium C&I, Large C&I, Extra Large C&I, Direct Serve	All
Fast DR	Load reduction with response time less than 10 minutes, suitable for providing ancillary services	All	Customer Specific
Third Party Aggregated	Represents primarily the existing TVA program	Medium C&I, Large C&I, Extra Large C&I	Customer Specific
Distributor Aggregated	Represents TVA's Distributor Aggregated Demand Response (DADR) Program	Residential, Small C&I, Medium C&I, Large C&I, Extra Large C&I	Customer Specific
Load Shifting	Represents TVA's 'Residential and Commercial Shift and Store Program	Residential, Small C&I, Medium C&I	Customer Specific
Voltage Regulation	Represents TVA's Conservation Voltage Regulation (CVR) and Dispatchable Voltage Regulation (DVR) Programs	Residential, Small C&I, Medium C&I	Not applicable

Load Impacts

Table 3-2 presents the load reductions per program participant (or unit impacts). Where current TVA DR programs exist, unit impacts are benchmarked to the values observed in those programs. Where there are no existing programs, unit impacts are based on the FERC study's Expanded Business as Usual (EBAU) scenario for Tennessee and values from Global's other recent potential studies.[6]

Table 3-2 Load Reduction Impact Assumptions [7]

DR Option	Unit of Impact	Residential	Small C&I	Medium C&I	Large C&I	Xlarge C&I	Direct Serve
AC DLC	kW load reduction per customer (summer)	1.0 kW	1.0 kW				
Space Heating DLC	kW load reduction per customer (winter)	1.0 kW	1.0 kW				
Water Heating DLC	kW load reduction per customer	0.5 kW	0.5 kW				
Capacity Reduction	Per Customer %Impact w/ tech		12%				
Capacity Reduction	Per Customer %Impact w/o tech		5%	12%	39%	100%*	100%*
Third Party Aggregated	Per Customer %Impact			40%	40%	40%	
Distributor Aggregated	Per Customer % Impact	30%	30%	40%	40%	40%	
Demand Reduction	Per Customer %Impact					100%*	100%*
Dynamic Pricing	Per Customer %Impact w/ tech	34%	15%	14%	14%	100%*	100%*
Dynamic Pricing	Per Customer %Impact w/o tech	17%	5%	9%	9%	100%*	100%*
Fast DR	Per Customer Summer %Impact w/ tech	30%	30%	39%	39%	100%*	100%*
Fast DR	Per Customer Winter %Impact w/ tech	30%	30%	39%			
Load Shifting	Per Customer %Impact	20%	25%	25%			
Curtailable	Per Customer %Impact					100%*	100%*

[6] Global has conducted numerous studies of DR potential in the last five years. We checked our input assumptions and analysis results against the results from these other studies which include AmerenUE, Los Angeles Department of Water and Power, and the State of New Mexico, and Avista Utilities.
[7] Gray shaded boxes indicate that a DR option is not applicable for that sector.
Xlarge and Direct serve % impacts are applied to eligible MW rather than eligible customers.
Impacts with asterisk (*) indicate programs for which 100% represents the expected interruptible load.

Demand Response Potential Results

Demand response has the potential to reduce peak demand by 1,504 MW to 1,520 MW in 2012. The achievable potential increases to a range of 3,870 MW to 4,579 MW in 2030.[8]

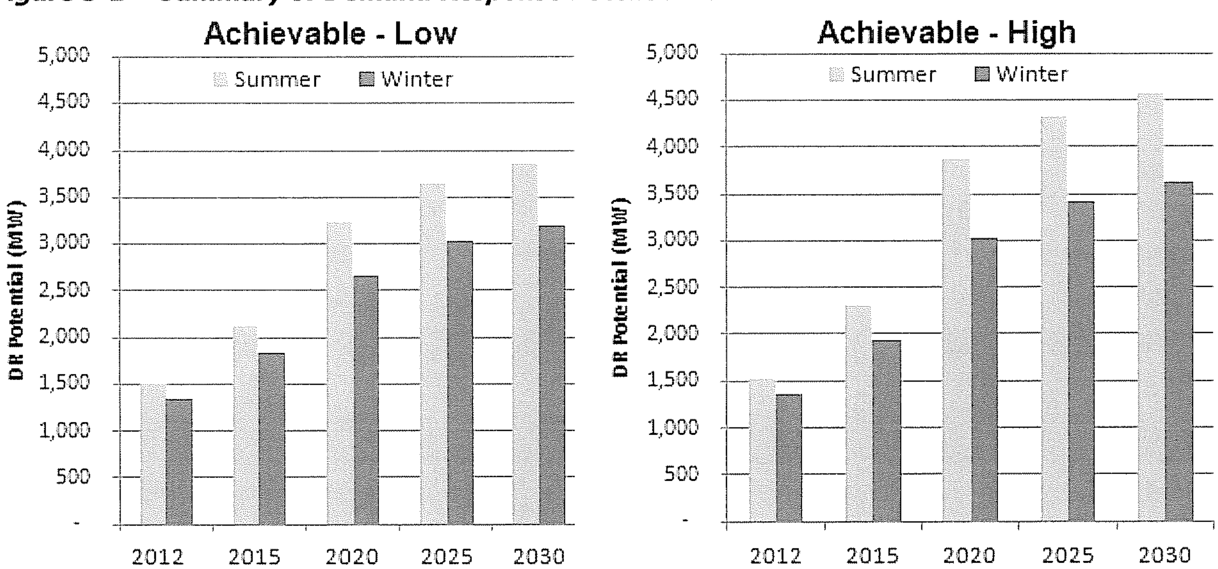
Table 3-3 presents the overall summary of demand response potential for the two cases. Figure 3-1 presents this information graphically. The primary observations are:

- In summer of 2012, achievable potential reduces peak demand by approximately 5%. This starting point takes into account the achievements in 2011 from TVA's current DR program portfolio.
- By summer of 2030, the achievable potential reduces peak demand by 10% to 12%. This level of savings represents an offset in growth of between 53% and 63%.
- In winter of 2012, achievable potential reduces peak demand by approximately 4%.
- By winter of 2030, the achievable potential reduces peak demand by 8% in the low case and 9% in the high case which represents an offset in growth of between 71% and 80%.

Table 3-3 Summary of Demand Response Savings for TVA

		2012	2015	2020	2025	2030
Summer	Peak Forecast (MW)	31,036	32,074	34,031	36,234	38,353
	Achievable - Low (MW)	1,504	2,137	3,245	3,662	3,870
	Achievable - High (MW)	1,520	2,301	3,872	4,331	4,579
	Achievable - Low (% of baseline)	***5%***	***7%***	***10%***	***10%***	***10%***
	Achievable - High (% of baseline)	***5%***	***7%***	***11%***	***12%***	***12%***
Winter	Peak Forecast (MW)	32,886	31,252	33,145	35,284	37,390
	Achievable - Low (MW)	1,353	1,782	2,618	3,030	3,199
	Achievable - High (MW)	1,363	1,881	2,985	3,422	3,616
	Achievable - Low (% of baseline)	***4%***	***6%***	***8%***	***8%***	***8%***
	Achievable - High (% of baseline)	***4%***	***6%***	***9%***	***9%***	***9%***

Figure 3-1 Summary of Demand Response Potential for TVA



[8] Fast DR is not included in the total potential estimates presented here. As discussed in more detail in Volume 3, Fast-DR events are considered distinct from traditional DR events. Customers can dual enroll in Fast DR and any other customer based dispatchable DR program, therefore the impacts associated with DR cannot be added to the total potential.

Potential Estimates by DR Program Type

Table 3-4and Table 3-5 show the range of achievable potential for each program type in both summer and winter. The primary observations from the analysis are:

- Capacity reduction has, by far, the largest contribution to the overall potential from all DR programs, with a 33% share in the total achievable potential in the high case in 2030. The achievable potential for this program represents a migration from the curtailable program to the capacity reduction program by 2016.[9]
- The Curtailable program is phased out completely by the year 2016 as all participants migrate into the Capacity Reduction option. In our experience, this trend is common in the industry as many utilities move away from emergency response programs and toward programs that can be integrated into wholesale markets based on economic dispatch models.
- While the total potential attributable to DLC varies widely from 645 MW and 17% in the low case to 1,174 MW and 26% in the high case DLC remains the second largest contributor to overall potential. The key difference between estimates of potential in the high and low case is the participation rates. The high case assumes an effective participation of 23.1% while the low case assumes an effective participation of 11.3%. DLC potential also varies from summer to winter; this is a result of the saturation of central air conditioning in the Tennessee Valley being higher than the saturation of electric heat.
- The Voltage Reduction programs also contribute substantially to the overall potential with CVR contributing 14% and DVR contributing 4% to overall potential.
- Savings from the Third Party Aggregated program come in fourth with an 11% share of the total potential in 2030. When combined with the Distributor Aggregated Program, which is very similar to the Third Party Program, the two programs represent 16% of the total potential in 2030.
- Savings from the Dynamic Pricing program are moderate with a total contribution of about 4% in 2030. Under a voluntary scenario, we assume a very conservative participation rate, which limits the potential of this program type.
- Load shifting has the smallest contribution to overall potential with about a 2% contribution in 2030.

[9] This migration is representative of the migration of customers from TVA's current 5MR and 60MR programs to the new Reserve Preservation program which falls within the capacity reduction program option for this study.

Table 3-4 Summary of Summer MW Savings by Program for TVA

DR Program	Type	2012	2015	2020	2025	2030
Direct Load Control	Achievable - Low	11	136	575	610	645
	Achievable - High	19	249	1,048	1,111	1,174
Curtailable	Achievable - Low	530	37	0	0	0
	Achievable - High	530	37	0	0	0
Capacity Reduction	Achievable - Low	441	1,086	1,283	1,369	1,452
	Achievable - High	447	1,117	1,360	1,453	1,543
Third Party Aggregator	Achievable - Low	395	518	520	522	523
	Achievable - High	395	518	520	522	523
Distributor Aggregator	Achievable - Low	61	86	129	134	139
	Achievable - High	62	96	173	181	188
Demand Reduction	Achievable - Low	1	16	68	73	77
	Achievable - High	1	16	68	73	77
Dynamic Pricing	Achievable - Low	2	29	132	161	191
	Achievable - High	2	33	141	171	203
Conservation Voltage Regulation	Achievable - Low	46	121	320	543	576
	Achievable - High	46	121	320	543	576
Dispatchable Voltage Regulation	Achievable - Low	16	42	112	190	202
	Achievable - High	16	42	112	190	202
Load Shifting	Achievable - Low	1	13	50	53	56
	Achievable - High	2	20	75	80	84
All Programs	**Achievable - Low**	**1,504**	**2,084**	**3,190**	**3,656**	**3,861**
	Achievable - High	**1,520**	**2,249**	**3,817**	**4,324**	**4,570**

Table 3-5 Summary of Winter MW Savings by Program for TVA

DR Program	Type	2012	2015	2020	2025	2030
Direct Load Control	Achievable - Low	5	62	259	275	290
	Achievable - High	9	115	481	510	539
Curtailable	Achievable - Low	507	34	0	0	0
	Achievable - High	507	34	0	0	0
Capacity Reduction	Achievable - Low	410	999	1,170	1,248	1,325
	Achievable - High	415	1,021	1,226	1,309	1,391
Third Party Aggregator	Achievable - Low	313	399	400	402	403
	Achievable - High	313	399	400	402	403
Distributor Aggregator	Achievable - Low	50	75	132	138	144
	Achievable - High	51	89	193	203	213
Demand Reduction	Achievable - Low	1	16	68	73	77
	Achievable - High	1	16	68	73	77
Dynamic Pricing	Achievable - Low	2	31	141	172	205
	Achievable - High	2	35	149	181	216
Conservation Voltage Regulation	Achievable - Low	47	115	300	502	524
	Achievable - High	47	115	300	502	524
Dispatchable Voltage Regulation	Achievable - Low	17	40	105	176	183
	Achievable - High	17	40	105	176	183
Load Shifting	Achievable - Low	1	11	42	45	47
	Achievable - High	1	16	62	66	70
All Programs	**Achievable - Low**	**1,353**	**1,782**	**2,618**	**3,030**	**3,199**
	Achievable - High	**1,363**	**1,881**	**2,985**	**3,422**	**3,616**

Figure 3-2 and Figure 3-3 show the range of achievable potential by customer class. The residential class has the largest contribution to overall potential at 41% in 2030 for the high achievable case. This is primarily due to participation in the DLC program option. Large C&I and Direct Serve come in second and third in overall contribution to potential, with 14% and 21% respectively, with their contribution being concentrated heavily in the capacity reduction program. Large, Medium C&I contribute 12% and 9% to overall potential respectively. Small C&I has the smallest contribution with 4%.

Figure 3-2 Achievable – Low Potential by Customer Class

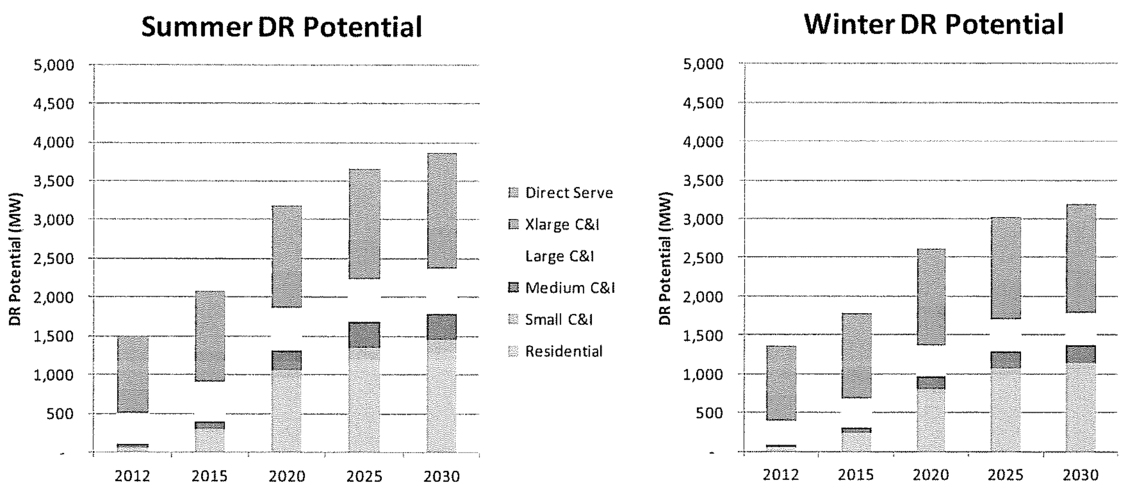
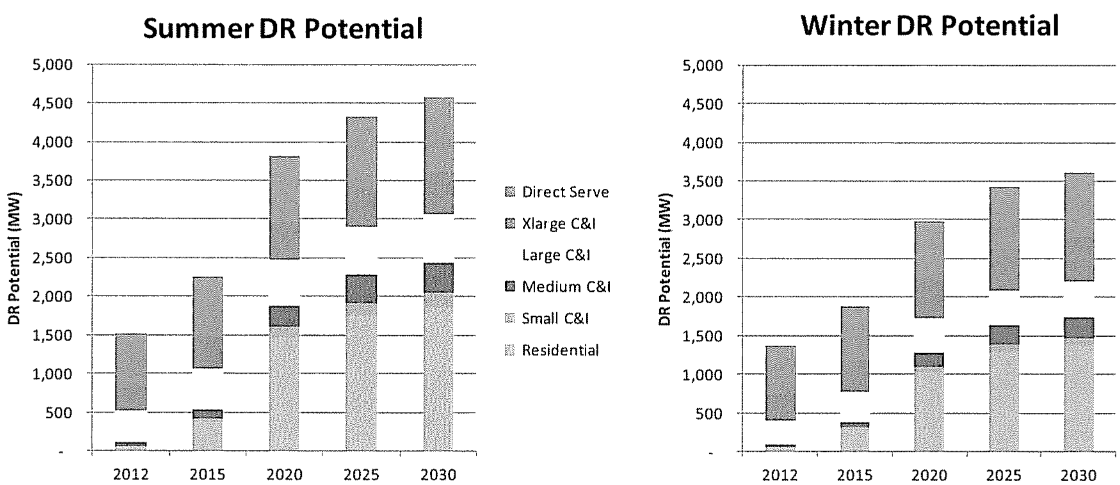


Figure 3-3 Achievable – High Potential by Customer Class



Summary of Cost-Effectiveness Analysis Results

Table 3-6 presents a summary of the cost-effectiveness results based on the TRC test for all programs.[10] The cost effectiveness tests were performed using a bottom up approach that employs cost assumptions based on secondary information and industry best practices.[11] The analysis was performed in this manner in order to provide TVA with realistic annual costs that can be passed on to distributors including: equipment costs, incentive costs, administrative, and marketing costs[12]. The results of the TRC test analysis show that the overall portfolio of DR programs is cost-effective.[13] The cost-effectiveness assessment is done for the Achievable - High level.

The most cost effective programs are Curtailable, Capacity Reduction, Demand Reduction, Dynamic Pricing and Fast DR. Curtailable has the highest B/C ratio due to a shortened program life of three years. Demand Reduction, Capacity Reduction, and Dynamic Pricing are also highly cost effective. These programs have lower administrative costs, and fewer equipment costs than the other non-aggregated programs. The voltage regulation programs are also considered cost effective, however it is important to note that costs for these programs are based solely on the incentive payment that TVA pays to the distributors. All equipment and implementation costs are assumed to be covered by that incentive and additional external (rate-based) costs and benefits to the distributor are not captured. The remaining programs; DLC, Third Party and Distributor Aggregated, and Load Shifting, are all cost effective with B/C ratios ranging from 1.05 to 1.31.

Table 3-6 Results of Cost-Effectiveness Screening (B/C ratios)

DR Option	Summer	Winter
DLC	2.07	2.02
Curtailable	18.15	17.22
Capacity Reduction	5.89	5.29
Third Party Aggregated	1.24	1.24
Distributor Aggregated	1.05	1.05
Demand Reduction	3.94	3.93
Dynamic Pricing	3.23	3.40
Fast DR	4.19	3.80
Conservation Voltage Regulation	1.60	1.60
Dispatchable Voltage Regulation	1.60	1.60
Load Shifting	1.31	1.09

DR Program Recommendations

The results of the DR assessment reveal that TVA has significant potential for demand response resources over the next two decades. Our analysis has shown that it is economically feasible for TVA to realize up to 11% reductions in summer peak and 9% reductions in winter peak by 2030 if it moves forward with the DR options represented in this report.

TVA's demand response programming efforts have a strong basis with large C&I customers in the field today. Moreover, a comprehensive suite of new programs is currently emerging from the planning phase and entering the implementation phase. In light of this study, Global provides the following recommendations to preserve and augment that momentum.

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[10] Cost effectiveness results by program and customer segment are included in Appendix B.

[11] Cost effectiveness inputs and assumptions are included in Appendix A.

[12] While utility incentives are not included in the TRC test as costs, we provide estimates of incentives that could reasonably be assumed for each program in the appendix.

[13] The $/kW payment for the Distributor aggregated program was adjusted from the $63/kW year in the TVA provided program data sheet to $55/kW year in order for the program to pass the economic screen. The Distributor Aggregated program was not cost effective given our assumptions in the analysis at the higher incentive rate. Payments from the utility to aggregators for both the 3rd Party Aggregated and Distributor Aggregated programs are included as implementation costs in the TRC analysis.

- ***Expand programs to include smaller customers:*** TVA's current DR programs total approximately 1,300 MW of DR, which indicates that the potential for future success with new DR programs is very high. The majority of the currently installed DR capacity is concentrated in the Large, X-Large, and Direct Serve customers. Targeting the largest customers first is an excellent strategy for utilities as they begin their DR efforts, however, as portfolios mature it becomes necessary to target other customer segments such as residential and small and medium C&I.
- ***Focus efforts on programs with the largest potential:*** DLC and Capacity Reduction are the DR programs with the largest opportunity for savings among end-users. DLC is a program that can be targeted to residential and small commercial customers and has been shown to be very successful given the right combination of technology and incentives.[14] Capacity reduction is gaining ground on the west coast as a highly favorable program with commercial and industrial customers. Customers particularly like the monthly capacity payments they receive all year long and the flexibility to determine their own reduction bid. Marketing efforts to expand DR program participation to the smaller customers should focus on DLC and capacity reduction.
- ***Voltage regulation programs need carefully designed incentives:*** Voltage reduction has significant potential to reduce demand on the distribution side. This is a unique program in that it involves infrastructure improvements to optimize and reduce voltage levels without affecting the power quality ultimately distributed to end users. Sufficient incentives will be needed to encourage distributors to participate in this program and therefore more information on the cost of specific voltage regulation technologies will need to be gathered.
- ***Coordinate distributor layer between TVA and end user:*** Because TVA is a wholesale provider, maintaining a cohesive DR message to end users may be challenging, especially as DR programs focus on residential and small C&I customers. We recommend dedicated resources to ensure that TVA programs are marketed and implemented consistently across distributors.
- ***Create internal DR targets:*** TVA should continue to evolve and formulate its specific objectives regarding demand response by creating targets and goals. Global recommends targets that fall within the range of achievable potentials identified in this study.
- ***Consider limiting the number of programs:*** TVA has a longer list of DR programs than many utilities do. TVA may consider limiting the number and type of DR programs to facilitate distributor and end-user understanding. Customers are often overwhelmed by too many options when it comes to utility programs, and many utilities with a large number of programs are now focused on reducing or bundling programs to make participation simpler for customers. We recommend focusing on those programs with the highest potential: capacity reduction in the C&I sectors, DLC in the residential sector, and voltage reduction for the distributors.
- ***Provide market-friendly customer incentives:*** Most customers are willing to offer their loads for participation in demand response programs if the utility is willing to compensate them for any inconvenience that they may realize due to the temporary service interruption. While incentive strategies must be structured in a way that ensures economic viability for the program, we have found that there is significant room to expand customer incentives while still maintaining cost-effectiveness.
- ***Provide enabling technology incentives:*** Enabling technology has been shown to improve the reliability of DR resources and to maximize load reduction in DR programs. It is therefore crucial to provide incentives to customers for adopting enabling technology in order to automate response to DR events.

[14] Southern California Edison, NV Energy, Florida Power & Light, and others all have very successful DLC programs with participation rates of 20% or more.

CHAPTER | 4

COMPARISON OF PREVIOUS POTENTIAL STUDIES

Analysis Approach

Previous studies of energy efficiency potential for the Valley and for the southeast region have produced a range of results. The objectives of this task are as follows:

- Develop a detailed report comparing the results of Task 1 to regional potential studies that are specific to the southeast.
- Consider the methodology, assumptions, approaches, estimated baselines, technical performance, adoption, and program/regulatory context of the studies.
- Create a matrix to enable side by side comparison of the studies.

List of Studies Considered

The reports Global reviewed are listed below.

- **EPRI National** — *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. (2010–2030)*
- **EPRI TVA** — *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs for the Tennessee Valley Authority (2010-2030)*
- **Georgia Tech** — *Meta-Review of Efficiency Potential Studies and Their Implications for the South*
- **Georgia Tech** — *Energy Efficiency in the South, a meta-study*
- **McKinsey** — *Unlocking Energy Efficiency in the U.S. Economy*
- **SEEA** — *Energy Efficiency in Appalachia "How Much More is Available, at What Cost, and by When?"*
- **REPP** — *Powering the South: A Clean & Affordable Energy Plan for the Southern United States*
- **PA Consulting** — *Tennessee Valley Authority: Energy Efficiency and Demand Response Plan 2008*
- **ACEEE** — *North Carolina's Energy Future: Electricity, Water, and Transportation Efficiency*
- **FERC** — *A National Assessment of Demand Response*
- **MISO** — *The Midwest ISO Study* (includes estimates of DR for regions within the Eastern Interconnection)

The review of these studies considered each study's analysis approach, the key input assumptions and sources for these assumptions, the relevant baseline, and the regulatory context. This report compares and contrast the studies listed above and the Global study for TVA with regard to these considerations.

This executive summary provides an at-a-glance overview of the comparison, with high-level conclusions and commentary. At the end of Volume 2, we examine each of the energy-efficiency studies in detail and compare them side by side with this Global study. In turn, at the end of Volume 3, we do the same for the demand-response studies.

Comparison Summary

Table 4-1 and Table 4-2 present a matrix of key elements from each of the studies considered in this task to provide a high-level overview.

Table 4-1 Energy Efficiency Studies at a Glance

Source	Area	Year Released	Type of Potential	10-yr Savings[15] Estimate	20-yr Savings Estimate
This Study: Global TVA	**TVA**	**2011**	**Economic**	**13.9%** ***21.7 TWh***	**24.8%** ***44.8 TWh***
			Achievable (High)	**9.8%** ***15.3 TWh***	**19.8%** ***35.8 TWh***
			Achievable (Low)	**5.1%** ***8.0 TWh***	**10.6%** ***19.1 TWh***
EPRI National, South Region	Southern region	2009	Economic	12.2%	13.4%
			MAP	10.0%	11.1%
			RAP	4.4%	8.1%
EPRI-TVA	TVA	2010	Economic	10%	10%
			RAP	4.6%	6.9%
Meta-Review of South EE Studies-Georgia Tech	Southern region	2009	MAP	1.18% per year	
			RAP	0.88% per year	
EE in the South-Georgia Tech	Southern region	2010	Program potential	12%	16%
McKinsey Study	U.S.	2009	NPV-positive	23%	
EE in Appalachia-SEEA	Appalachian region	2009	Program potential	11%	24%
Powering the South-REPP	SERC and FRCC regions	2002	Clean Power Plan potential	13.5%	22.9%
TVA- PA Consulting	TVA	2008	Program potential	*11.7 TWh*	*19.5 TWh*
North Carolina study- ACEEE	North Carolina	2010	Medium program	14.9%	
			High program	20.4%	

The most directly comparable studies to the Global TVA study are the EPRI National Study and EPRI's 2010 study of the TVA service territory. These both use a similar bottom-up modeling approach.

The most dissimilar studies are the REPP "Powering the South" study, because of its age, and the McKinsey study because of its different definitions and methodologies, as discussed in Volume 2.

As far as baseline forecasts, the assumptions used in the various studies are all relatively similar. Except for the REPP study mentioned above, all the baseline forecasts are relatively recent and

[15] 10-year and 20-year savings are approximations. Because several studies start one or two years earlier or later, they do not fit in these categories exactly, but this simplification is made for comparison purposes.

include the effects of the EISA lighting standards. However, Global's baseline forecast includes the appliance and equipment standards that were adopted in 2010, which was a major year for new standards. This has the most significant impact in the residential sector.

Overall, Global's savings estimates are higher than either of the EPRI studies. They are in line with the other studies to the extent they are comparable. Direct comparison from study to study should be made mindfully, taking into account the caveats and considerations spelled out in the EE and DR Volumes.

Table 4-2 Demand Response Studies at a Glance

Source	Area	Year Released	Type of Potential	10-yr Savings Estimate	20-yr Savings Estimate
This Study: Global TVA	**TVA**	**2011**	**Achievable (High)**	**11%** ***3.8 GW***	**12%** ***4.6 GW***
			Achievable (Low)	**10%** ***3.2 GW***	**10%** ***3.9 GW***
FERC National Assessment of DR	U.S.	2009	Economic	20%	
			Achievable	14%	
			Expanded BAU	9%	
MISO Assessment	MISO	2010	Program potential	7.6%	7.6%
	Eastern Interconnection			11.1%	10.8%

The more limited landscape of DR potential studies shows a fair amount of convergence on the range of achievable potentials. There is less complexity and variation in the way that DR potentials are analyzed. With the exception of some differences in definition of potentials in the FERC National study, these three studies are relatively comparable.

ENERGIZING VIRGINIA: EFFICIENCY FIRST

American Council for an Energy-Efficient Economy
Summit Blue Consulting
ICF International
Synapse Energy Economics

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CONTENTS

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ABOUT THE AMERICAN COUNCIL FOR AN ENERGY-EFFICIENT ECONOMY (ACEEE)

ACEEE is a nonprofit organization dedicated to advancing energy efficiency as a means of promoting economic prosperity, energy security, and environmental protection. For more information, see http://www.aceee.org. ACEEE fulfills its mission by:

- Conducting in-depth technical and policy assessments
- Advising policymakers and program managers
- Working collaboratively with businesses, public interest groups, and other organizations
- Organizing conferences and workshops
- Publishing books, conference proceedings, and reports
- Educating consumers and businesses

Projects are carried out by staff and selected energy efficiency experts from universities, national laboratories, and the private sector. Collaboration is key to ACEEE's success. We collaborate on projects and initiatives with dozens of organizations including federal and state agencies, utilities, research institutions, businesses, and public interest groups.

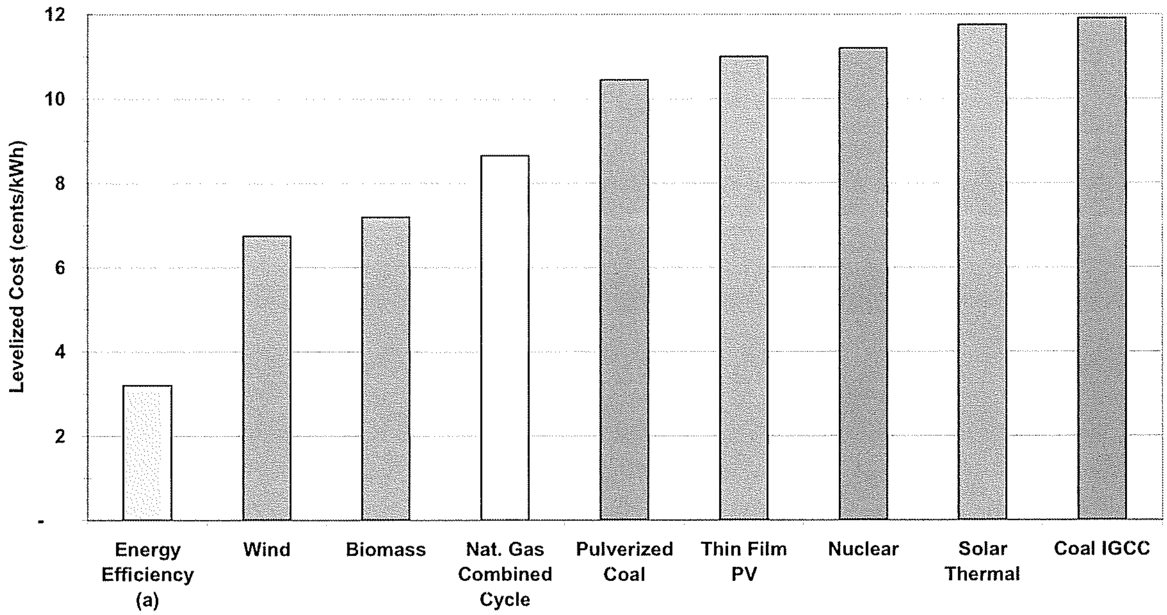
Support for our work comes from a broad range of foundations, governmental organizations, research institutes, utilities, and corporations.

EXECUTIVE SUMMARY

Over the past decade, the Commonwealth of Virginia has experienced a rapid increase in its demand for electricity due in large part to economic and population growth, particularly in Northern Virginia. This rapid increase in Virginia's demand for electricity could negatively impact the Commonwealth's future economic growth by causing further increases in utility prices and the potential for decreased reliability. Energy efficiency and demand response have the potential to moderate these impacts while at the same time improving the economic health of the Commonwealth.

Energy efficiency and demand response are the lowest-cost resources available to meet this growing demand and the quickest to deploy for near-term impacts (see Figure ES-1).

Figure ES-1. Estimates of Levelized Cost of New Energy Resources



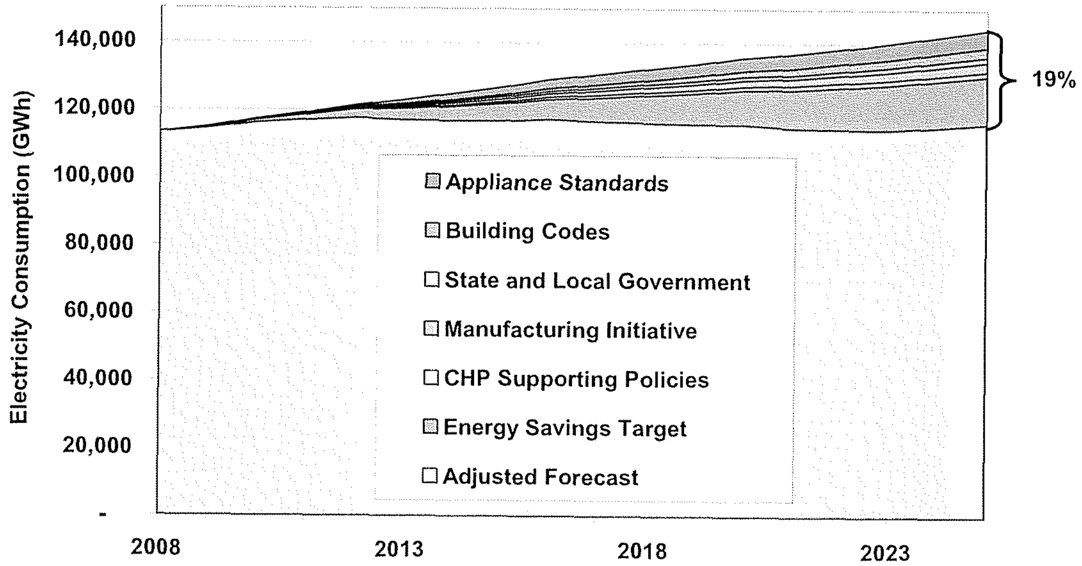
As can be seen in Figure ES-2, ACEEE estimates a suite of energy efficiency policies and programs that could save 10,000 GWh of electricity, or meet 8% of Virginia's electricity needs in 2015. By 2025, savings grow to 28,000 GWh, or 19% of Virginia's electricity needs in 2025, in our medium policy scenario.

Policy Recommendations

ACEEE suggests that policymakers consider the following suite of eleven policy recommendations:

1. Energy Efficiency Resource Standard (EERS)
2. Expanded Demand Response Initiatives
3. Combined Heat and Power (CHP) Supporting Policies
4. Manufacturing Initiative
5. State Facilities Initiative
6. Local Government Facilities Initiative
7. Building Energy Codes
8. Appliance and Equipment Efficiency Standards
9. Research, Development & Deployment (RD&D) Initiative
10. Consumer Education and Outreach
11. Low-Income Efficiency Programs

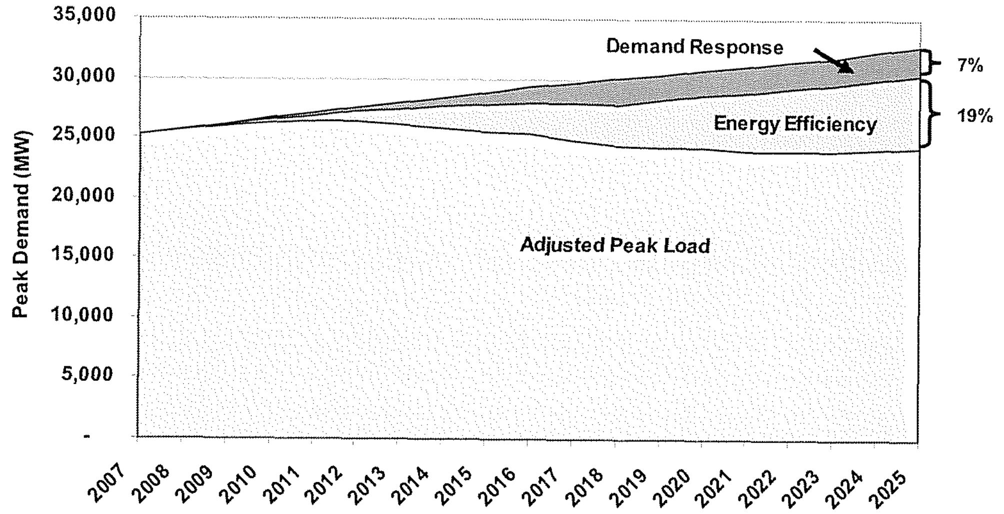
Figure ES-2. Share of Projected Electricity Use Met by Energy Efficiency Policies — Medium Scenario



These recommendations draw from the best practice policies currently implemented throughout the country. The EERS represents the core of these policies, providing a foundation upon which the manufacturing initiative, government facilities, appliance standards, and building codes can be layered to fully achieve the goals. Energy efficiency can also reduce peak demand in Virginia, which occurs during the summer on days when electricity needs are highest (see Figure ES-3).

In addition, we find that a suite of demand response (DR) recommendations, which focuses on shifting energy from peak periods to off-peak periods and cutting back electricity needs on days with the highest needs, is a critical component of reducing peak demand in Virginia. Figure ES-3 presents the combined effects of energy efficiency and demand response on peak reductions in a medium case policy scenario.

Figure ES-3. Estimated Reductions in Summer Peak Demand through Energy Efficiency and Demand Response — Medium Scenario (2025 peak reduction = 8,400 MW, or 26%)



ACEEE also considered a more aggressive suite of policies that would increase energy savings to 39,000 GWh in 2025, meeting 27% of Virginia's electricity needs in that year. Combined, the high scenario suite of energy efficiency policies plus the potential for demand response can reduce peak demand by nearly 11,000 MW in 2025, or a 36% reduction in peak demand.

Economic and Jobs Impacts

The energy savings from these efficiency policies can cut the electricity bills of customers by a net $500 million in 2015. Net annual savings grow nearly five-fold to $2.2 billion in 2025. While these savings will require some public and customer investment, by 2025 net cumulative savings on electricity bills will reach $15 billion. To put this into context, an average household will save a net $5 on its monthly electricity bill by 2015 and $20 per month by 2025. These savings are the result of two effects. First, participants in energy efficiency programs will install energy efficiency measures, such as more efficient appliances or heating equipment, therefore lowering their electricity consumption and electric bills. In addition, because of the current volatility in energy prices, efficiency strategies have the added benefit of improving the balance of demand and supply in energy markets, thereby stabilizing regional electricity prices for the future.

Investments in efficiency have the additional benefit of creating new, high-quality "green-collar" jobs in the Commonwealth and increasing both wages and Gross State Product (GSP). Our analysis shows that energy efficiency investments can create nearly 10,000 new jobs in Virginia by 2025 (see Table ES-1), including well-paying trade and professional jobs needed to design and install energy efficiency measures. These new jobs, including both direct and indirect employment effects, would be equivalent to almost 100 new manufacturing plants relocating to Virginia, but without the public costs for infrastructure or the environmental impacts of new facilities.

Table ES-1. Economic Impact of Energy Efficiency Investments in Virginia

Macroeconomic Impacts	2015	2025
Jobs (Actual)	675	9,820
Wages (Million $2006)	63	583
GSP (Million $2006)	202	882

Conclusions

The Commonwealth of Virginia finds itself at a juncture with respect to its energy future. The state can either continue to depend solely upon conventional energy resource technologies to meet its growing needs for electric power as it has for more than a century, or it can chose to slow—or even reduce—future demand for electricity by investing in energy efficiency and demand response. As this assessment documents, there are plenty of cost-effective energy efficiency and demand response opportunities in the state. However, as this report also discusses, these opportunities will not be realized without changes in policies and programs in the state. We suggest a wide array of energy efficiency and demand response policies and programs that have proven successful in the past, and can meet 90% of the increase in the state's electricity needs over the next 18 years, and 120% of the increase in peak demand. These policies and programs are already proving themselves in other states, delivering efficiency resources and reducing consumer electric expenditures. **And**, these policy and programs can accomplish this at a lower cost than building new generation and transmission, while at the same time creating nearly 10,000 new, high-quality "green collar" jobs by 2025.

These policy and program suggestions should not be viewed as prescriptive, but as the starting point for a dialog among stakeholders on how to realize the efficiency resource that is available to the state. ACEEE's suggestions are based on our review of existing opportunities and stakeholder discussions, and reflect proposals that we think are politically plausible in the state. Clearly there are other policies and programs, some of which we suggest in our aggressive scenario, which could be implemented to realize even more of the available energy efficiency resource.

Also, we do not suggest that these recommendations will meet all of the state's future energy needs. While energy efficiency is perhaps the only new energy resource that is available near term and that can make an important contribution in the longer term, the state will need additional resources to meet the remainder of the new load and to replace older, dirtier power plants in the coming years. Most importantly, energy efficiency can buy time for a robust discussion about what other resource choices—both conventional and alternative—the state makes in the future.

GLOSSARY

ENERGY POLICY AND ORGANIZATIONS

(ASHRAE) American Society of Heating, Refrigerating and Air-Conditioning Engineers: Organization of over 50,000 professionals in the air-conditioning, heating, refrigerating and ventilating fields. Support the integration of increased energy efficiency in building design via technological enhancements of these systems (http://www.ashrae.org/).

Avoided Costs: The marginal costs incurred by utilities for additional electric supply resources. Used by utilities to evaluate the cost-effectiveness of energy efficiency programs.

(EERS) Energy Efficiency Resource Standard: A simple, market-based mechanism to encourage more efficient generation, transmission, and use of electricity and natural gas. An EERS consists of electric and/or gas energy savings targets for utilities. All EERS include end-user energy saving improvements that are aided and documented by utilities or other program operators. Often used in conjunction with a Renewable Portfolio Standard (RPS). (See ACEEE's fact sheet for state details: http://aceee.org/energy/ state/policies/2pgEERS.pdf.)

(EISA 2007) Energy Independence and Security Act of 2007: Law covering issues from fuel economy standards for cars and trucks to renewable fuel and electricity to training programs for a "green collar" workforce to the first federal mandatory efficiency standards for appliances and lighting.

ENERGY STAR®: A joint program of the U.S. Environmental Protection Agency and the U.S. Department of Energy helping residential customers save money and protect the environment through energy-efficient products and practices (http://www.energystar.gov/). Includes appliance efficiency standards and new building codes.

(EPAct) Energy Policy Act: Law directing U.S. energy policy; first passed in 1992 and major revisions were passed in 2005 and 2007.

(ESCO) Energy Service Company: Provides designs and implementation of energy savings projects. The ESCO performs an in-depth analysis of the property, designs an energy-efficient solution, installs the required elements, and maintains the system to ensure energy savings.

(ESPC) Energy Service Performance Contracting: A financing technique that uses cost savings from reduced energy consumption to repay ESCO's (see above) for the cost of installing energy conservation measures and other services.

(FEMP) Federal Energy Management Program: U.S. Department of Energy program "works to reduce the cost and environmental impact of the Federal government by advancing energy efficiency and water conservation, promoting the use of distributed and renewable energy, and improving utility management decisions at Federal sites" (http://www1.eere.energy.gov/femp/about/index.html).

(FERC) Federal Energy Regulation Commission: Federal agency that "regulates and oversees energy industries in the economic, environmental, and safety interests of the American public" (www.ferc.org).

(IRP) Integrated Resource Plan: A comprehensive and systematic blueprint developed by a supplier, distributor, or end-user of energy who has evaluated demand-side and supply-side resource options and economic parameters and determined which options will best help them meet their energy goals at the lowest reasonable energy, environmental, and societal cost (http://www.energycentral.com/ centers/knowledge/glossary/home.cfm).

(LIHEAP) Low-Income Home Energy Assistance Program: A federally funded program intended to assist low-income households that pay a high proportion of household income for home energy, primarily in meeting their immediate home energy needs.

(NERC) North American Electric Reliability Corporation: NERC's mission is to improve the reliability and security of the bulk power system in North America. To achieve that, NERC develops and enforces reliability standards; monitors the bulk power system; assesses future adequacy; audits owners, operators, and users for preparedness; and educates and trains industry personnel. NERC is a self-regulatory organization that relies on the diverse and collective expertise of industry participants. As the Electric Reliability Organization, NERC is subject to audit by the U.S. Federal Energy Regulatory Commission and governmental authorities in Canada (www.nerc.com).

GENERAL REPORT TERMINOLOGY

Additionality: A framework for evaluating whether projects are deserving of offset credits in climate change mitigation strategies. If a project would have been undertaken and financially attractive regardless of incentives of any kind, then offering incentives to the project is said to yield no "additionality." The standard thinking is that financial incentives/offset credits should be offered only to projects that would not have happened *but for* the offering of credits.

Cumulative Savings: Sum of the total annual energy savings over a certain time frame.

Demand Side Management (DSM): Programs that focus on minimizing energy demand by influencing the quantity and use-patterns of energy consumption by end users, as opposed to supply side management, which focuses on investments in system infrastructure.

Energy Efficiency: The implementation of programs and policies that minimize the consumption of energy resources while stimulating economic growth.

Incremental Annual Savings: Energy savings occurring in a single year from the current year programs and policies only.

Percent Turnover: Percentage of technology replaced on burnout with more efficient technology. Does not include retrofits.

Potential: amount of energy savings possible

- **Achievable Potential**: Potential that could be achieved through normal market forces, new state building codes, equipment efficiency, and utility energy efficiency programs
- **Economic Potential**: Potential based on both the Technical Potential and economic considerations (e.g., system cost, avoided cost of energy)
- **Technical Potential:** Potential based on technological limitations only (no economic or other considerations)

Replace-on-Burnout: The act of waiting until a technology's end of life before replacing it with a more energy-efficient technology. Cost basis is the incremental cost of choosing a more efficient technology over a less efficient one. Incremental cost usually means incremental equipment cost with no labor cost; that is, there is no labor cost or it is the same in both cases and thus a zero-sum.

Retrofit Measure: The act of replacing a technology with a more energy-efficient technology before its end of life. Cost basis is the full cost of the new technology, including installation.

Total Annual Savings: Energy savings occurring in a single year from the current year programs and policies and counting prior year savings. Sum of all Incremental Annual Savings.

INDUSTRY and BUILDINGS TECHNOLOGY

(CHP) Combined Heat and Power: method of using waste heat from electrical generation to offset traditional process or space heating. Also called cogeneration (cogen).

Electricity Use Feedback: System that monitors home/building electricity use and provides real time feedback to occupants. This allows occupants to increase energy efficiency.

ENERGY STAR® New Homes: 15% electricity savings over a comparable size home.

HVAC: Heating, ventilation, and air conditioning system.

(NAICS) North American Industry Classification System: 6-digit code used to group industries by product.

UTILITY TERMS

Coincidental Peak: The sum of two or more peak loads that occur in the same time interval.

Coincidental Peak Factor: The ratio of annual peak demand savings (kW) from an energy efficiency measure to the annual energy savings (kWh) from the measure; also called Coincidence Factor.

Demand Response: The reduction of customer energy usage at times of peak usage in order to help address system reliability, reflect market conditions and pricing, and support infrastructure optimization or deferral. Demand response programs may include dynamic pricing/tariffs, price-responsive demand bidding, contractually obligated and voluntary curtailment, and direct load control/cycling.

Deregulation: Allows a rate payer to choose other electricity providers over a local provider. Deregulation efforts vary from reducing to completely eliminating a local monopoly on electricity.

Distributed Energy Resource: Electrical power generation or storage located at or near the point of use, as well as demand-side measures

Distributed Generation: Electric power generation located at or near the point of use.

Distributed Power: Electrical power generation or storage located at or near the point of use.

Electricity Distribution: Regulating voltage to usable levels and distributing electricity to end-users from substations

Electricity Generation: Converting a primary fuel source (e.g., coal, natural gas, or wind) into electricity.

Electricity Transmission: Transport of electricity from the generation source to a distribution substation, usually via power lines.

Henry Hub: The market price for natural gas is by convention set at the Henry Hub (which is a physical location in southern Louisiana where a number of pipelines from the Gulf of Mexico originate). Futures and spot market contracts for delivery of gas are traded on the New York Mercantile Exchange (NYMEX) with regional wholesale prices set at key hubs where pipelines originate or come together. These prices are set relative to the Henry Hub price with adders for transportation and congestion.

(IOU) Investor-Owned Utility: Also known as a private utility, IOU's are utilities owned by investors or shareholders. IOU's can be listed on public stock exchanges.

(ISO) Independent System Operator: Entity that controls and administers nondiscriminatory access to electric transmission in a region or across several systems, independent from the owners of facilities.

Levelized Cost: The level of payment necessary each year to recover the total investment and interest payments at a specified interest rate over the life of the measure.

Peak Demand: The highest level of electricity demand in the state measured in megawatts (MW) during the year.

Peak Shaving: Technologies or programs that reduce electricity demand only during peak periods (frequently combined with "valley filling" policies that shift consumption to periods of low demand. The combination is referred to as load shifting.)

PJM: PJM Interconnection is a Regional Transmission Organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

Power Pool: Two or more inter-connected electric systems planned and operated to supply power in the most reliable and economical manner for their combined load requirements and maintenance programs.

Renewable Generation: Electric power generation from a renewable energy source such as wind, solar, sustainably harvested biomass, or geothermal.

(RTO) Regional Transmission Organization: An independent regional transmission operator and service provider that meets certain criteria, including those related to independence and market size. Controls and manages the transmission and flow of electricity over large areas.

(REC) Rural Electric Cooperative: REC's are nonprofit, cooperative utilities that provide electricity to rural areas and are owned by all customers of that utility.

Transformer: Electrical device that changes the voltage in AC circuits from high-voltage transmission lines to low voltage distribution lines.

Wholesale Competition: A system in which a distributor of power would have the option to buy its power from a variety of power producers, and the power producers would be able to compete to sell their power to a variety of distribution companies.

Wholesale Electricity: Power that is bought and sold among utilities, non-utility generators, and other wholesale entities, such as municipalities.

Wholesale Power Market: The purchase and sale of electricity from generators to resellers (that sell to retail customers) along with the ancillary services needed to maintain reliability and power quality at the transmission level.

INTRODUCTION

Over the past decade, the Commonwealth of Virginia has experienced a rapid increase in its demand for electricity. Significant economic and population growth has been a primary driver of this rise in demand, particularly in the Northern Virginia region, which has historically been home to two of the fastest growing counties in the nation.[1] The impact of population growth on electricity demand is compounded by the fact that electricity consumption per customer has risen dramatically in the past several decades. Today the average residential customer consumes in Virginia about 14,000 kWh per year, 25% more than the national average, and the average commercial customer uses 50% more electricity than it did in 1990 (EIA 2007b). This rapid increase in Virginia's demand for electricity could impact the Commonwealth's future economic growth. As demand outstrips electric supplies, the added strain on the grid during peak times, particularly in Northern Virginia could result in reliability problems as early as 2011 (DMME 2007), and result in price increases and greater price volatility. As this report will demonstrate, energy efficiency and demand response have the potential to moderate these impacts while simultaneously improving the economic health of the Commonwealth.

Energy efficiency and demand response are the least-cost resources available to meet this growing demand and the quickest to deploy for near-term impacts. While energy efficiency focuses on reducing overall electricity consumption, demand response is essential to reducing electric load at those peak times of Virginia's electricity needs. Not only is demand for electricity growing in the Commonwealth, but rapidly increasing fuel and electricity prices are being felt by consumers and straining household budgets. Recently, an 18% electricity rate increase was approved for Dominion Virginia to recover rising fuel costs (SCC 2008a) and Appalachian Power (APCo) has similarly requested an increase in its fuel rate. Both price increases are in advance of rate caps coming off in December of 2008, which are expected to further raise prices. Unlike supply-side energy resources, efficiency and demand response are the only resources that can actually begin to *reduce* customer electric bills by reducing overall consumption. These clean energy resources are not only important to consumers and electric reliability in the Commonwealth, but they also can be vital to the economy. Investing in efficiency also creates new "green collar" jobs in fields such as construction and technology development and deployment.

A growing consensus is emerging that the Commonwealth must do more to realize this clean energy resource. And because the energy policy choices Virginia makes now will define its energy future for years to come, it is important that policymakers and consumers be aware of the policy options available to them.

The goal of this study is to inform policymakers and stakeholders of the opportunities for energy efficiency and demand response in Virginia, and to suggest policies the Commonwealth could implement to tap into these clean energy resources. Our results are designed to help educate policymakers and the public at large about the importance of energy efficiency and demand response, and to facilitate policy development in Virginia for the next several years by identifying policy and technical opportunities for achieving major energy efficiency savings and benefits.

This report is organized into the following sections:

- ***Background:*** *Reviews the electricity market in Virginia, including recent actions and future opportunities regarding energy efficiency and demand response.*
- ***Project Overview and Methodology:*** *Provides a context for ACEEE's work with state-level energy efficiency and demand response potential studies and an overview of both the project approach and analysis methodology.*

[1] Loudoun County and Prince William County (DMME 2007).

- ***Reference Case:*** *Discusses the reference case electricity, peak demand, and price forecasts used in this analysis.*

- ***Energy Efficiency Resource Assessment:*** *Estimates the cost-effective potential, from the customer's perspective, for increased energy efficiency in the state's residential, commercial, and industrial sectors by 2025 through the adoption of specific energy-efficient technology measures. The resource assessment goes beyond what the state can achieve through penetration of specific programs and policies.*

- ***Energy Efficiency Policy Analysis:*** *Outlines the recommended policies for Virginia to adopt to tap into the energy efficiency resource potential. This section presents the electricity and peak demand impacts from energy efficiency, the associated costs, and an evaluation of program costs using two cost-effectiveness tests (TRC and the Participant cost tests). Also included in this section is an estimation of carbon dioxide emissions impacts.*

- ***Demand Response Analysis:*** *Estimates the potential for increased demand response in Virginia and makes specific recommendations to the Commonwealth.*

- ***Macroeconomic Impacts:*** *Estimates the impact of energy efficiency policies on Virginia's economy, employment, and energy prices.*

BACKGROUND

Virginia Electricity Market

The Commonwealth of Virginia briefly experimented with utility deregulation starting in 1999, but the competition that deregulation was expected to create failed to materialize. Legislation introduced in 2007 ended the state's commitment to deregulation, although the replacement system offered a "hybrid" alternative to the regulation that existed prior to 1999. Through this system, utilities are still subject to rate caps but are also guaranteed a rate of return, allowing them to borrow money in order to finance projects such as building new capacity to meet demand (DMME 2007).

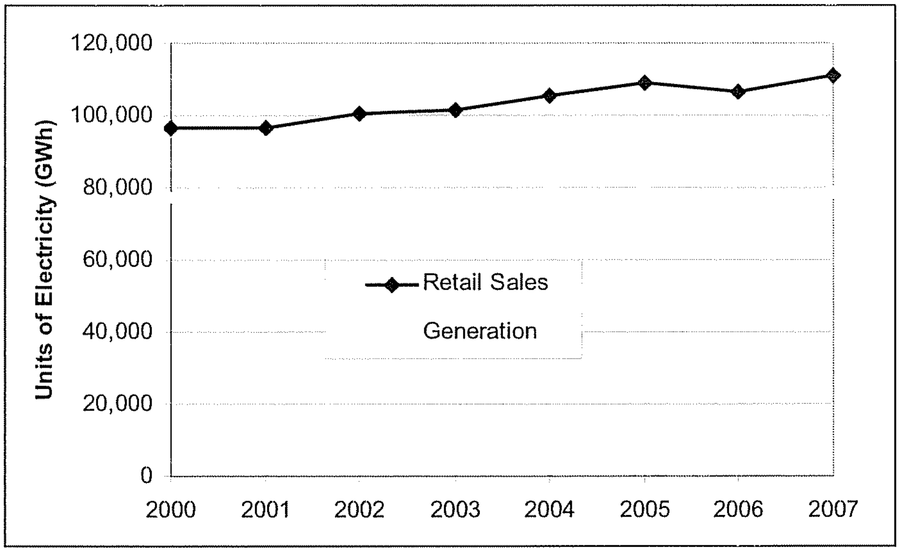
Electricity consumption in Virginia grew at an average annual rate of 2.0% over the 2000-2007 period of deregulation (EIA 2007b). As can be seen in Figure 1, electricity generation in the Commonwealth has remained below the level of demand, meaning that Virginia is a net importer of 30-40% of its electricity. All but a small portion of Virginia in the southwest is part of the PJM Interconnection, a regional transmission organization in the Mid-Atlantic that provides reliability planning, manages a wholesale power market, and manages long-term regional electric transmission planning. In general, the price of power is greater in the PJM market than that generated in-state, so a greater reliance on imported power is likely to increase the price of electricity.

Retail rate caps set in place as part of Virginia's regulatory process are set to expire at the end of 2008, which will open the door to higher electricity prices as rising fuel costs make it increasingly difficult for utilities to recover their operating costs. Dominion Virginia Power has already been granted an 18% rate increase for higher fuel costs by state regulators as of June 2008, and Appalachian Power Company (APCo) is awaiting approval for a rate-adjustment clause (see Figure 2 for a map of these electric service territories).

There are several major generation and transmission projects in the Commonwealth aimed at meeting growing demand. Construction of a coal-fired generation plant in southwestern Wise County began in June 2008 and is slated to be finished in four years. This facility, called the Virginia Hybrid Energy Center, will be capable of producing 585 MW of electricity when it comes online in 2012. In November 2007, the Nuclear Regulatory Commission (NRC) granted Dominion an Early Site Permit, though the company still requires additional licenses from both the NRC and the State Corporation Commission (SCC) to construct a third generating unit at its North Anna nuclear facility located in

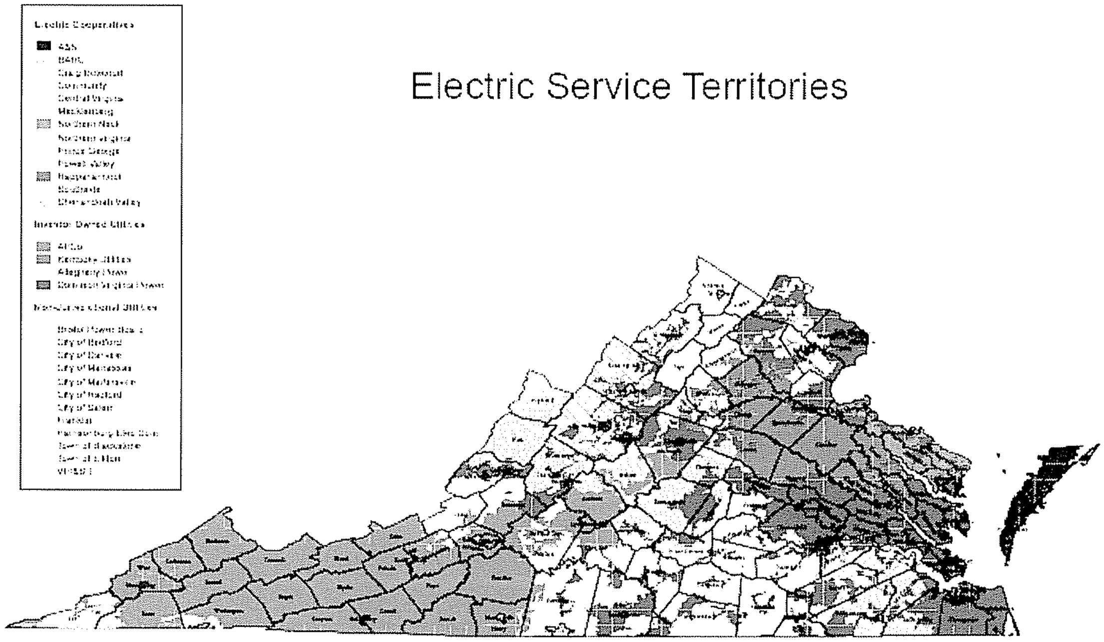
Louisa County. The new unit would add 1,520 MW of capacity to the facility, which is already capable of generating 1,786 MW, though commercial operation would not start until 2016 at the earliest. Also, Dominion owns a 600 MW Natural Gas Combined Cycle Generator plant in Buckingham County set to open in 2011 (Dominion 2007). There are two major transmission projects proposed that would affect the Commonwealth. Dominion and TrAILCo—a subsidiary of Allegheny Power—have proposed a 500 kV, 65-mile overhead transmission line stretching from Pennsylvania to Loudoun County with the purpose of serving future demand in Northern Virginia and other Mid-Atlantic states. Additionally, in 2007 PJM approved the construction of PATH-Allegheny's 250-mile, 765 kV transmission line extending from American Electric Power's (AEP) John Amos substation in St. Albans, West Virginia, to AEP's Bedington, northeast of Martinsburg, Maryland. Another 50 miles of twin-circuit 500 kV transmission lines will connect the Bedington substation to a new substation near Kemptown, southeast of Frederick, Maryland, which will be owned by Allegheny Power. This project is slated for completion in 2012.

Figure 1. Electricity Sales and Generation in Virginia, 2000-2007



Source: EIA 2007b, 2008a

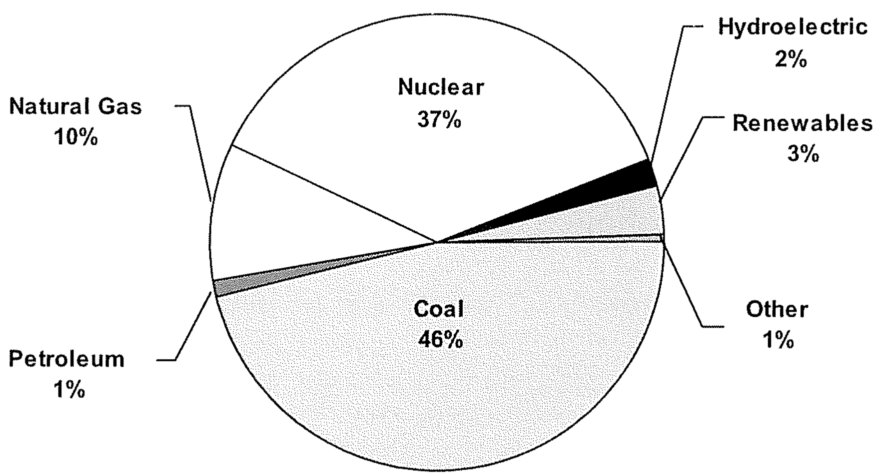
Figure 2. Electric Service Territories in Virginia



In 2006, Virginia generated 74,237 GWh of electricity (see Figure 1 and Figure 3). The majority of this in-state generated electricity came from coal-fired power plants (46%) and nuclear (37%). By comparison, the national average mix of electricity generation is 49% from coal and 19% from nuclear (EIA 2007b). In the same year, the state consumed 106,721 GWh of electricity, making the state a net importer of about 30% of its total electricity consumption (see Figure 1).

Figure 3. 2006 Virginia Electricity Generation by Fuel Type

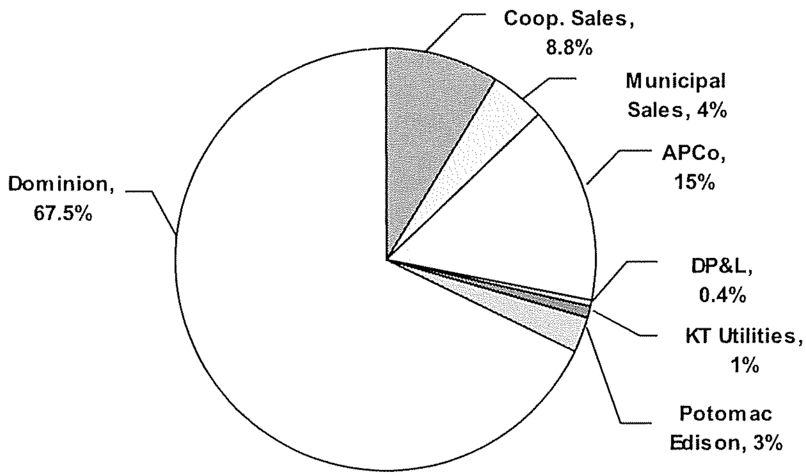
Total Generation: 74,237 GWh



Source: EIA 2008a

Electricity is delivered in Virginia to consumers by three types of providers: investor-owned utilities (IOUs), rural electric cooperatives (coops), and municipal electric suppliers. As can been seen in Figure 4, of the three types of providers, IOUs dominate the sales in the state (87%), with Dominion securing a 67.5% market share. Cooperatives and municipal utilities account for the remaining 13% of electricity sales.

Figure 4. Electricity Deliveries (GWh) by Supplier in 2006



Source: EIA 2007a

The failure of restructuring to introduce competition into Virginia's electricity market has perpetuated its vertical integration. The vast majority of electricity services (99.9%) are bundled; a negligible amount (<1.0%) is delivered to a third party for distribution.

Role of Energy Efficiency and Demand Response

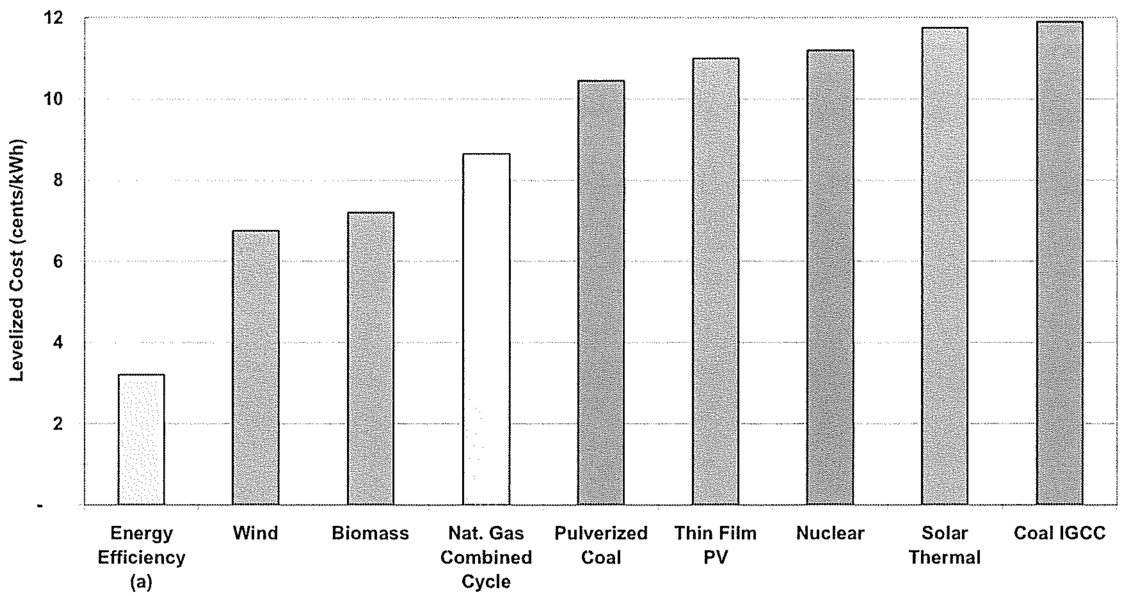
Virginia utilities are proposing several projects to meet the Commonwealth's increasing demand for electricity, as discussed above. The proposed investments in new generation and transmission have thus far not been complemented by notable efforts to expand the state's demand-side efficiency policies. In fact, Virginia ranked 38th out of the 50 states in ACEEE's 2006 state energy efficiency scorecard (Eldridge et al. 2007).

Recently, Virginia has taken steps towards a more pro-active focus on demand-side management. Recognizing that adding new capacity cannot completely satisfy the state's future electricity needs, Governor Timothy Kaine inserted an enactment clause into the March 2007 electricity restructuring legislation (S.B. 1416) stating that the Commonwealth shall have a goal of reducing electricity consumption by 10% (of 2006 consumption) by 2022 and directed the State Corporation Commission to conduct a proceeding to evaluate the stated goal and submit its findings and recommendations to the Governor and the General Assembly. The November 2007 SCC report states that the staff believes that the 10% electricity consumption reduction goal set forth by the General Assembly is attainable by 2022, though it suggests further exploration into the programs needed to achieve the goals and the cost-effectiveness of the programs (SCC 2007).

At the utility level, Dominion has recently introduced programs that aim to increase the prevalence and success of demand-side management within the state. In January 2008, the Virginia utility commission approved Dominion's implementation of nine pilot programs whose goal is to evaluate customer acceptance of various DSM programs (SCC 2008b). Through these programs, Dominion plans to address the potential for energy conservation, customer education, demand response, and load management to curtail electricity consumption within its service territory. In June 2008, Dominion introduced an aggressive energy conservation and demand reduction plan that includes the installation of "smart grid" technology, which Dominion will introduce to its Virginia customers pending Commission approval. Dominion estimates that these programs will shave electricity demand and consumption by 850 MW and 2,788 MWh by 2015, providing a significant step towards achieving Governor Kaine's goal of a 10% reduction (Dominion 2008).

In leading states, energy efficiency is meeting 1 to 2% of the state's electricity consumption each year (Nadel 2007; Hamilton 2008) at a cost of less than 3¢ per kWh (Kushler, York and Witte 2004), compared with a utility-avoided cost of about 6 to 8¢ per kWh in Virginia (see Figure 10).[2] States across the country, including California, Connecticut, Massachusetts, Minnesota, New York, and Vermont, are realizing the benefits of energy efficiency today, and have enacted policies and programs that effectively tap into their energy efficiency resources. Results from these states show that energy efficiency represents an immediate low cost, low risk strategy to help meet the state's future electricity needs (York, Kushler, and Witte 2008). In contrast, new supply options—either traditional or renewable—now cost significantly more, as is suggested in Figure 5.

Figure 5. Cost of New Energy Resources



Source: All estimates are midpoint of ranges from Lazard (2008), except (a) which is Nadel, Shipley and Elliott (2004).

Together, energy efficiency and demand response can delay the need for expensive new supply in the form of generation and transmission investments (Elliott et al. 2007; 2007b), thus keeping the future cost of electricity affordable for the state and freeing up energy dollars to be spent on other resources that expand the state's economy. In addition, a greater share of the dollars invested in energy efficiency go to local companies that create new jobs compared with conventional electricity resources, where much of the money flows out of state to equipment manufacturers and energy suppliers.

[2] The avoided cost analysis does not take into account a cost of carbon that would be imposed under a federal cap and trade program. If we assume a cost for carbon, which most experts predict, avoided costs to utilities could range from 8 to 10 cents per kWh.

Barriers to Energy Efficiency and Demand Response

While experience has demonstrated that energy efficiency and demand response resources are cost-effective and achievable, we have learned that they will not occur without specific policy interaction due to pre-existing market barriers. These barriers include:

- Awareness of energy efficiency opportunities—as one industrial manager characterized it, "you have to know what fruit looks like if you are going to harvest the low-hanging fruit" (Johnson 2008).
- Principal-agent barrier where the person making the efficiency investment does not benefit from the energy savings (e.g., a landlord installing efficient lighting when the tenant reaps the energy bill savings).
- Regulatory barriers (e.g., regulation may discourage utilities from investing in energy efficiency because they cannot fully recover their costs or make an attractive return on their DSM investments).
- Financial hurdles—the "Warren Buffet problem" that the private sector is inclined to do one large deal rather than lots of small deals, and energy efficiency is by its nature small and dispersed.
- Expanding demand response is a challenge since most consumers don't understand demand resources and its benefits, and that it requires both utility and customer investments in new infrastructure

Proactive legislative initiatives and policies are thus required to overcome these barriers and allow energy efficiency and demand response resources to be realized to their full potential.

PROJECT APPROACH AND METHODOLOGY

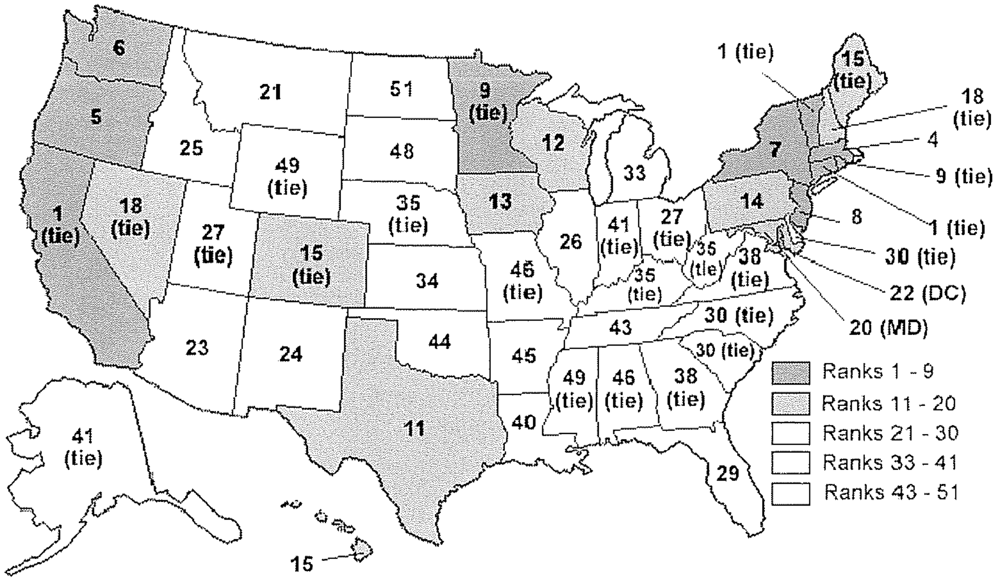
Overall Project Context: Why We Chose Virginia

For a number of years, ACEEE has published state clean energy scorecards, the first editions ranking utility-sector energy efficiency program spending and performance data, and more recently with a comprehensive ranking of state energy efficiency policies identifying exemplary programs and policies within several energy efficiency policy categories. The 2007 edition of the Scorecard was the first edition of this more comprehensive approach and the policy categories included:

1. Spending on Utility and Public Benefits Energy Efficiency Programs
2. Energy Efficiency Resource Standards (EERS)
3. Combined Heat and Power (CHP)
4. Building Energy Codes
5. Transportation Policies
6. Appliance and Equipment Efficiency Standards
7. Tax Incentives
8. State Lead by Example Programs

In the 2007 Scorecard, ACEEE noted that the top tier states, as shown in Figure 6, needed little or no help to continue to improve their energy efficiency programs and policies. Rather it was the middle tier of states, which are moving more slowly towards better energy efficiency programs but have started the process, that offered the best opportunity to encourage a quicker transition to greater energy efficiency. In ACEEE's 2007 Scorecard, Virginia ranked # 38 as shown on the map and was, therefore, considered a middle tier state.

Figure 6. 2007 State Scorecard Results



Source: Eldridge et al. 2007

Recent interest by Virginia's Governor Tim Kaine and his administration has resulted in legislation directing various state agencies to review and consider new energy efficiency policies to reduce the state's growing energy demand. Some utilities, such as Dominion, are beginning to explore demand-side management through pilot programs. Due to this increased interest in energy efficiency and Virginia's growing energy demand (especially in the northern region of the state), ACEEE determined that the state might benefit from an analysis of how energy efficiency and complementary demand response initiatives could work in a cost-effective manner to fill the expected energy demand gap.

Stakeholder Engagement

ACEEE did not presume to know what energy policies would work best in Virginia. Talking to a broad range of stakeholders was an essential part in tailoring our proposal to fit the unique needs of the Commonwealth. Engaging the many interest groups in Virginia was a significant undertaking. We endeavored to meet in person with as many different sectors as possible in order to get the feedback required to better understand Virginia's specific energy structure and needs. We met with many of the environmental groups; the Governor's staff; the Virginia Manufacturing Association membership; utility companies including Dominion, Appalachian Power, and the Virginia Association of Electric Cooperatives; the State Commonwealth Commission; and various other interested organizations in the state. We also called various legislators' offices and representatives of the low income communities for their input.

We shared the draft report of this study with representatives of all of these stakeholders for their review, and their comments have been incorporated in this report as appropriate. A final follow up with stakeholders included presentations of the reports results at the Virginia Manufacturers Forum in Richmond on September 17th, meetings with environmental organizations on the 18th, and finally a presentation at the Governor's Commonwealth of Virginia Energy and Sustainability Conference held in Richmond from Sept. 17th through 19th.

Analysis

The remainder of the report presents a description of the analysis methodology and results in the following order:

- ***Reference Case:*** In addition to the extensive stakeholder phase of this study, the first step in conducting an energy efficiency and demand response potential study for Virginia was to collect data and to characterize the state's current and expected patterns of electricity consumption over the study time period (2008-2025). In this section, we describe the assumed reference forecasts for electricity, peak demand, electricity supply prices, and avoided costs based on available data that ACEEE has been able to collect and projections developed by Synapse Energy and Economics, as presented in Appendix A.1.

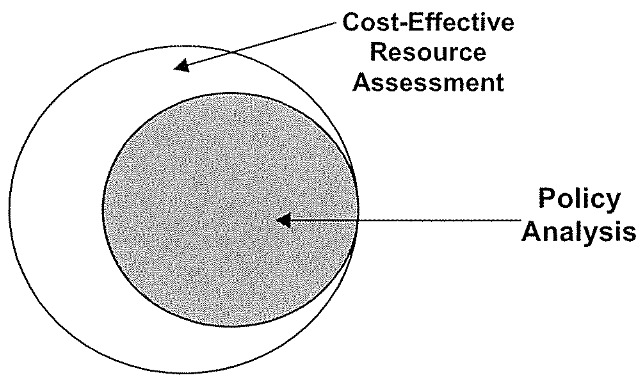
- ***Energy Efficiency Resource Assessment:*** Following the Reference Case section is the energy efficiency resource assessment, which examines the overall potential in the state for increased cost-effective electricity efficiency using technologies and practices of which we are currently aware (see Figure 7). Cost-effectiveness is evaluated from the customer's perspective (i.e., a measure is deemed cost-effective if its cost of saved energy is less than the average retail rate of electricity). We review specific, efficient technology measures that are technically feasible for each sector; analyze costs, savings, and current market share/penetration; and estimate total potential from implementation of the resource mix. The technology assessment is reported by sector (i.e., residential, commercial, and industrial) and includes an analysis of potential for expanded CHP, which was prepared by ICF International. An important caveat for the reader to note is that we review only existing technologies and practices that have reasonable market share but do not consider emerging technologies and practices with very low market share or that have yet to emerge. Therefore, potential for increased efficiency is likely higher throughout the study time period given the likelihood that some emerging technologies will be commercialized and become cost-effective. See Appendix C for a detailed methodology of the resource potential analysis by sector.

- ***Energy Efficiency Policy Analysis:*** For this analysis, we developed suites of energy efficiency policy recommendations based on successful models implemented in other states and in consultation with stakeholders in Virginia. This analysis assumed a reasonable program and policy penetration rate, and therefore is less than the overall resource potential (see Figure 7). We drew upon our resource assessment and evaluations of these policies in other states to estimate the electricity savings and the investments required to realize the savings. The cost-effectiveness of the recommended programs and policies are evaluated using the TRC test and the Participant test. We also estimate the reductions in peak demand that would occur as a result of these energy efficiency policies and programs. See Appendix B for detailed results.

- ***Demand Response (DR) Analysis:*** The Demand Response Analysis, prepared by Summit Blue Consulting, assesses current demand response activities in Virginia, uses benchmark information to assess the potential for expanded activities in Virginia, and offers policy recommendations that could foster DR contributing appropriately to the resource mix in Virginia that could be used to meet electricity needs. Potential load reductions are estimated for a set of DR programs that represent the technologies and customer types that span a range of DR efforts, and are in addition to the demand reductions resulting from expanded energy efficiency investments. The demand response policy analysis is presented in Appendix D.

- ***Macroeconomic Impacts:*** Based on the electricity savings, program costs, and investment results from the policy analysis, we ran ACEEE's macroeconomic model, DEEPER, to estimate the policy impacts on jobs, wages, and gross state product (GSP). For a more detailed discussion of DEEPER and the macroeconomic analysis, see Appendix F.

Figure 7. Levels of Energy Efficiency Potential Analysis



REFERENCE CASE

The first task in developing an energy efficiency and demand response potential assessment is to determine a reference case forecast of energy consumption, peak demand, and electricity prices in the state in a "business as usual" scenario. In this section we report the reference case assumptions for the analysis time period, 2008-2025. See Appendix A for more detailed information on the reference case assumptions.

Electricity (GWh) and Peak Demand (MW)

We base our forecast of electricity consumption growth on PJM's 2008 annual load forecast through 2022, using only its service territories in Virginia to derive weighted-average growth rates for Virginia. We then apply this overall forecast to actual 2007-year electric sales data by sector for Virginia (EIA 2007b) and adjust sector-specific growth rates using *Annual Energy Outlook* sector growth rate ratios for the South Atlantic region (EIA 2007c). Using this methodology, and extending the forecast through 2025 to cover the study period of this analysis, total electricity consumption in the state is projected to grow in the reference case at an average annual rate of 1.4% between 2008 (the analysis base year) and 2025, and 1.2%, 2.0%, and 0.2% in the residential, commercial, and industrial sectors, respectively. Actual electricity consumption in the residential, commercial, and industrial sectors in 2007 was 110,924 GWh (EIA 2007b), and in the reference case grows to 126,833 GWh by 2015 and 144,195 GWh by 2025 (see Figure 8 and Appendix A).

We derive a peak demand (MW) forecast for Virginia from the electricity forecast described above and assume a 55% load factor, based on PJM load data for Dominion in 2007. Using this methodology, we estimate a 2008 peak demand of about 26,000 MW, rising to nearly 33,000 MW in 2025 and an average annual growth rate of 1.4%.

Utility Avoided Costs

At ACEEE's request, Synapse Energy Economics developed simplified, high-level projections of utility production and avoided marginal costs. We then used these results in ACEEE's analysis to estimate the cost-effectiveness of energy efficiency measures and assess the macroeconomic impacts. The avoided cost estimates are based upon a number of simplifying and conservative assumptions that the stakeholder group considered reasonable for the purpose of this high-level policy study. These simplifications include use of a single annual average avoided energy cost to evaluate the economics of energy efficiency measures rather than different avoided energy costs for energy efficiency measures with different load shapes. In a further conservatism, we did not include a cost of compliance with anticipated greenhouse gas emissions regulations. As a result, the production and avoided cost estimates used should be viewed as unrealistically low. A detailed discussion of the assumptions and avoided cost estimates can be found in Appendix A.2.

Figure 8. Electricity Forecast by Sector in the Reference Case

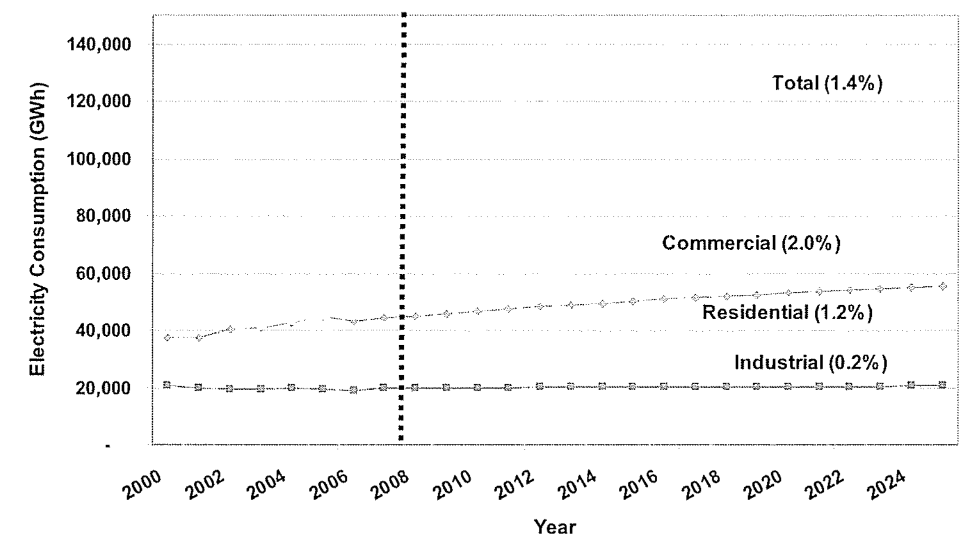
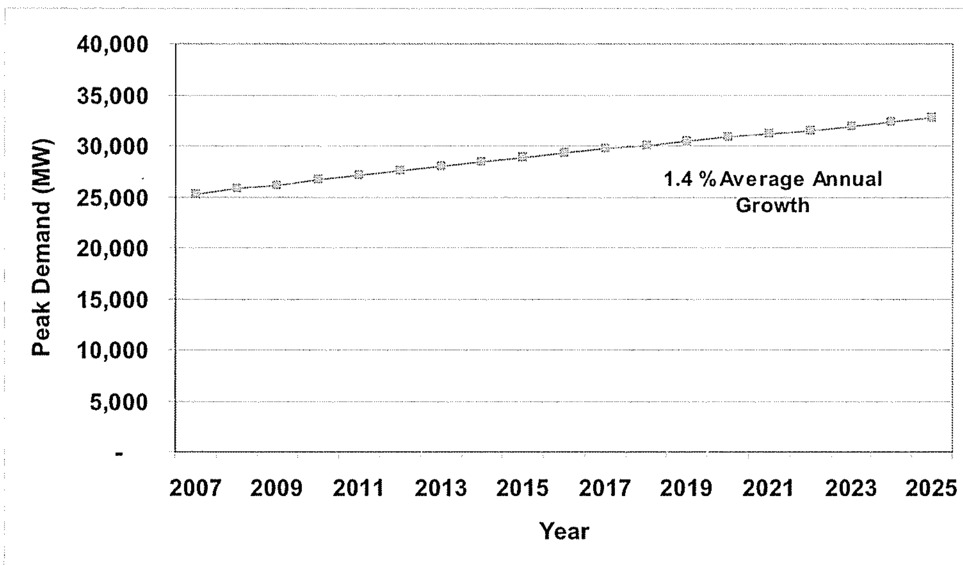
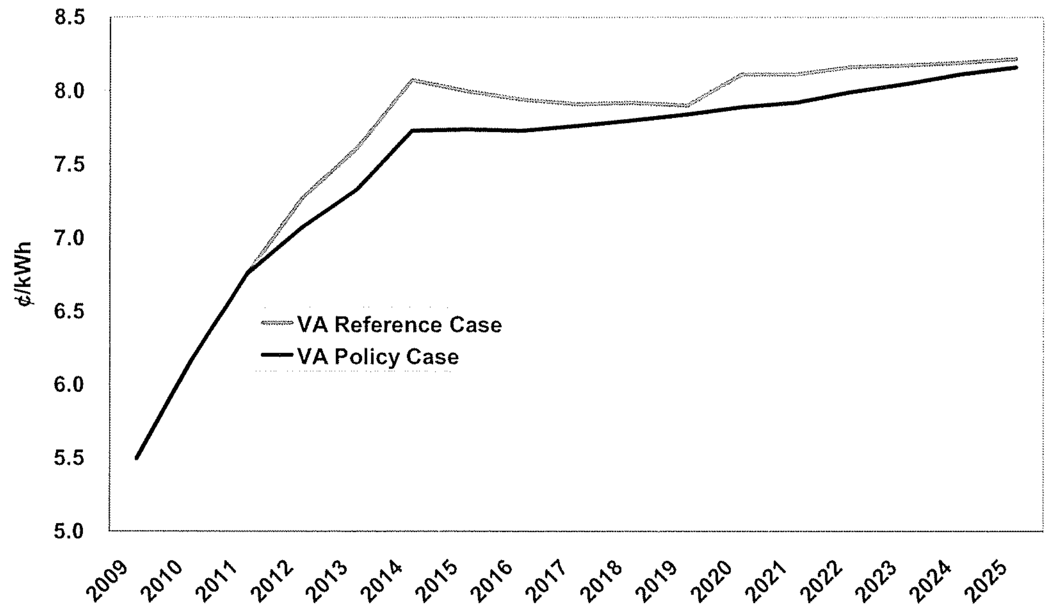


Figure 9. Virginia Peak Demand Forecast



Because the level of energy efficiency and demand response measures assessed in this study significantly change the requirements for future resources, we developed two sets of production and avoided costs projections. The first case reflects the market conditions that would be anticipated in the reference case. The second case reflects the medium energy efficiency policy case discussed below. As would be anticipated, the policy case produced modestly lower avoided resource costs than the reference case, as can be seen in Figure 10. As a further conservatism in our analysis, we used this second, lower set of costs in valuing the savings that resulted from the analyzed policies and programs.

Figure 10. Estimates of Average Annual Avoided Resource Costs



It is important to note that because these projections represent a highly stylized representation of costs, we suggest that a more detailed assessment of costs be undertaken as part of the Commonwealth's energy planning process that can reflect the locational and temporal variation across the state and throughout the year.

Retail Price Forecast

ACEEE also developed a possible scenario for retail electricity prices in the reference case. Readers should note the important caveat that ACEEE does not aim to predict what electricity prices in Virginia will be in either the short or long term. Rather, our goal is to suggest a possible scenario, and to use that scenario to estimate impacts from energy efficiency on electricity customers in Virginia.

Table 1 shows 2007 electricity prices in Virginia (EIA 2008a) and our estimates of retail rates by customer class over the study time period. This price scenario is based on three key factors. First, we use the average generation cost of electricity in Virginia over the time period from the analysis done by Synapse Energy Economics (discussed above). Next, we use estimates of retail rate adders (the difference between generation costs and retail rates, which accounts for transmission and distribution costs) from the *Annual Energy Outlook* for the Southeastern Electric Reliability Council (SERC) (EIA 2007c). Finally, we estimate expected near-term increases due to fuel adjustments by investor-owned utilities and expectations of rate caps expiring in December 2008. More details on the methodology and assumptions used to develop these projections are presented in Appendix A.2.

Table 1. Retail Electricity Price Forecast Scenario in Reference Case (cents per kWh in 2006$)

	2007*	2010	2015	2020	2025	Average
Residential	8.5	10.1	10.0	10.1	10.5	10.0
Commercial	6.3	9.1	8.9	9.1	9.4	8.9
Industrial	4.9	6.8	6.8	6.9	7.2	6.8
Average	6.9	8.8	8.7	8.9	9.2	8.7

Note: These figures are in real, 2006-year dollars and therefore do not take into account inflation.
* Actual rates (EIA 2008a), converted to 2006$

ENERGY EFFICIENCY COST-EFFECTIVE RESOURCE ASSESSMENT

This section presents results from our assessment of cost-effective energy efficiency resources in residential and commercial buildings, the industrial sector, and combined heat and power (CHP). Cost-effectiveness of more efficient technologies is determined from the customer's perspective (i.e., a measure is deemed cost-effective if its cost of saved energy is less than the average retail rate of electricity for a given customer class). More detailed information on methodology and results is given in Appendix C. Table 2 presents a summary of energy efficiency potential by sector in 2025. This assessment includes only existing technologies and practices. We anticipate that new and emerging technologies and market learning will significantly increase the cost-effective efficiency resource potential by 2025.

Table 2. Summary of Cost-Effective Energy Efficiency Potential in Virginia by Sector (2025)

Sector	Efficiency Potential (GWh)	As % of Electricity Consumption in 2025
Residential	14,328	26%
Commercial	19,191	28%
Industrial	5,152	25%
Combined Heat & Power	5,700	6%*
Total	44,371	31%

** Note: As percentage of commercial and industrial sectors combined.*

Residential Buildings

To examine the cost-effective potential for energy efficiency resources in Virginia's residential sector, we considered a scenario with widespread adoption of cost-effective energy efficiency measures during the 18-year period from 2008 to 2025. We evaluated 34 efficiency measures that might be adopted in existing and new residential homes based on their relative cost-effectiveness. An upgrade to a new measure is considered cost-effective if its levelized cost[3] of conserved energy (CCE) is less than 10 cents per kWh saved, which is the average retail residential electricity price in Virginia over the study time period (see Table 1). However, the substantial majority (85%) of the total efficiency potential has a levelized cost of 8 cents per kWh saved or less and 41% of the measures have a cost of 3 cents per kWh or less. For the sum of all measures, we estimate a levelized cost of less than 4 cents per kWh saved (see Table 3).[4] See Appendix C.1 for a detailed methodology and specific efficiency opportunities and cost-effectiveness for residential buildings (Table C.1). Also shown in Appendix C.1 is a characterization of a typical household in Virginia and the resulting energy bill savings from implementation of the efficiency measures described below.

[3] Levelized cost is a level of investment necessary each year to recover the total investment over the life of the measure.
[4] Assuming a 5% real discount rate.

Table 3. Residential Energy Efficiency Potential and Costs by End-Use

End-Use	Savings (GWh)	Savings (%)	% of Efficiency Potential	Weighted Levelized Cost of Saved Energy ($/kWh)
HVAC	5,940	11%	41%	$ 0.043
Water Heating	1,695	3%	12%	$ 0.074
Lighting	2,939	5%	21%	$ (0.003)
Refrigeration	447	1%	3%	$ 0.060
Appliances	76	0%	0.5%	$ 0.078
Furnace Fans	1,005	2%	7%	$ 0.035
Plug Loads	900	2%	6%	$ 0.021
Electricity Use Feedback	376	1%	3%	$ 0.022
Existing Homes	**13,378**	**24%**	**93%**	**$ 0.034**
New Homes	**949**	**2%**	**7%**	**$ 0.054**
All Electricity	**14,328**	**26%**	**100%**	**$ 0.036**

We estimate an economic potential for efficiency resources of 14,328 GWh in the residential sector over the 18-year period of 2008–2025, a potential savings of 26% of the reference case electricity consumption in 2025 (Table 3). Existing homes can reduce electricity consumption by 24% through the adoption of a variety of efficiency measures (see Appendix C, Table C.1). While newly constructed homes built today can readily achieve 15% energy savings (ENERGY STAR® new homes meet this level of efficiency), we also estimate that new homes can reach 30% to 50% energy savings cost-effectively. We estimate that new residential homes can yield electricity savings of about 949 GWh by 2025, or 7% of total potential savings in the residential sector.

In the residential sector, significant savings from electricity efficiency resources are realized through improved housing shell performance (e.g., insulation measures, duct sealing and repair, reduced air infiltration, and ENERGY STAR windows) and more efficient heating, ventilation, and air conditioning (HVAC) equipment and systems.[5] HVAC equipment, air distribution, efficient furnace fans, and load reduction measures account for 48% of potential savings.

Substantial savings are also attributed to improvements in lighting systems and water heating (including both more efficient water heaters as well as water-consuming appliances). As a fraction of total savings potential in the residential sector, lighting constitutes 21% and water heating 12% of potential savings (see Figure 11). There is considerable potential for efficiency resources in both existing and new homes in Virginia to be realized simply by replacing household incandescent light bulbs with more efficient compact fluorescent light bulbs (CFLs). Measures to reduce hot water loads (such as high-efficiency clothes washers, low-flow showerheads, and water heater jackets and pipe insulation) can yield additional savings for households with electric water heaters. The use of more efficient water heaters, particularly advanced technologies such as heat-pump water heaters, can further reduce electricity used for water heating.

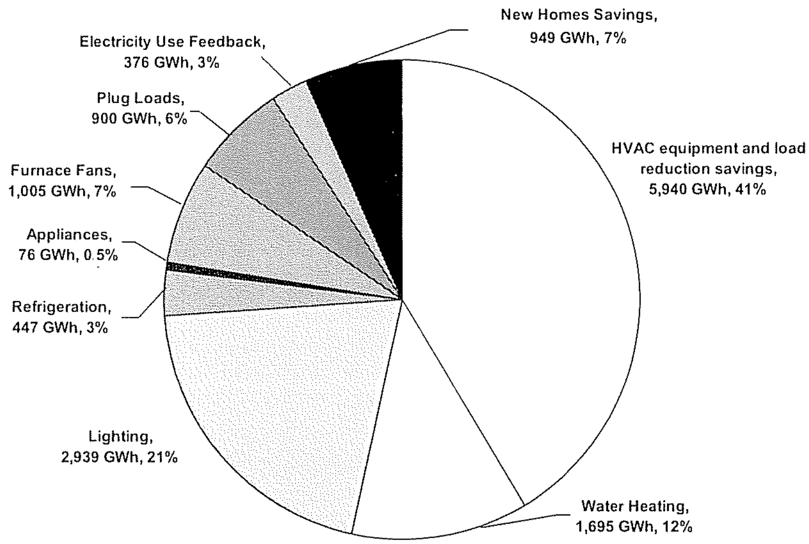
More efficient household appliances can also yield significant savings. Our analysis shows the savings potential of replacing existing refrigerators, clothes washers, and dishwashers with units that are better than minimum ENERGY STAR models (Consortium for Energy Efficiency "Tier 2" in most cases), or by having builders install these more efficient models in new homes. Another 6% of the total savings potential can be attributed to reducing the power consumption of electronic devices that use considerable amounts of energy in standby mode. We include a measure for reducing television power consumption in active mode, which is based on ENERGY STAR's Draft 2 Specification revision. These measures are among the most cost-effective in the residential sector. The balance of potential savings comes from installing a real-time energy use feedback mechanism. Although

[5] Savings from air-conditioners assume a baseline of 13 SEER equipment, which is the recently updated federal standard.

involving a behavioral component, in-home monitors, which allow residents to track how much electricity their house is using, have been documented to result in significant and persistent savings.

Figure 11. Residential Energy Efficiency Potential in 2025 by End-Use in Virginia

Total: 14,328 GWh
26% of Projected Electricity Consumption in 2025



Commercial Buildings

We examined thirty-six energy efficiency measures in the commercial buildings sector to determine the potential for electricity resources from energy efficiency. Thirty-three of these measures are applicable to existing buildings, and each of these measures was categorized by end-use: HVAC; water heating; refrigeration; lighting; office equipment; and appliances/other. An upgrade to a new measure is considered cost-effective if its levelized cost of conserved energy (CCE) is less than 8.9 cents per kWh saved, which is the average retail commercial electricity price in Virginia over the study time period (see Table 4). In addition we examined savings for new buildings that are 15%, 30%, and 50% better than current energy code. To calculate the potential from each of these measures, we first gathered information on baseline electricity consumption in Virginia commercial buildings, and then characterized new measures by collecting data on savings, costs, lifetime of the measure, and the percent of buildings for which the measure is applicable. See Appendix C.2 for a detailed description of the methodology. Table 4 and Figure 12 show results for energy efficiency potential in commercial buildings by 2025. Results by specific measure are shown in Appendix C.2. We estimate that by 2025, Virginia can reduce its commercial building electricity consumption by 28% at a levelized cost of about $0.018 per kWh saved.[6]

The largest share (44%) of the resource potential is in lighting, which includes measures such as replacing incandescent lamps, fluorescent lighting improvements, and lighting control measures such as daylight dimming systems and occupancy sensors. The second largest share comes from HVAC measures: reduced HVAC loads; improved heating and cooling systems; and HVAC equipment control measures (21% of resource potential). Measures to reduce HVAC loads include low-e replacement windows, duct testing and sealing, and roof insulation. Equipment upgrades include high-efficiency unitary air conditioners and heat pumps for smaller buildings and high-efficiency

[6] Assuming a 5% real discount rate.

chillers and systems for larger buildings. Measures to further increase HVAC efficiency through controls include energy management systems and whole-building retrocommissioning.

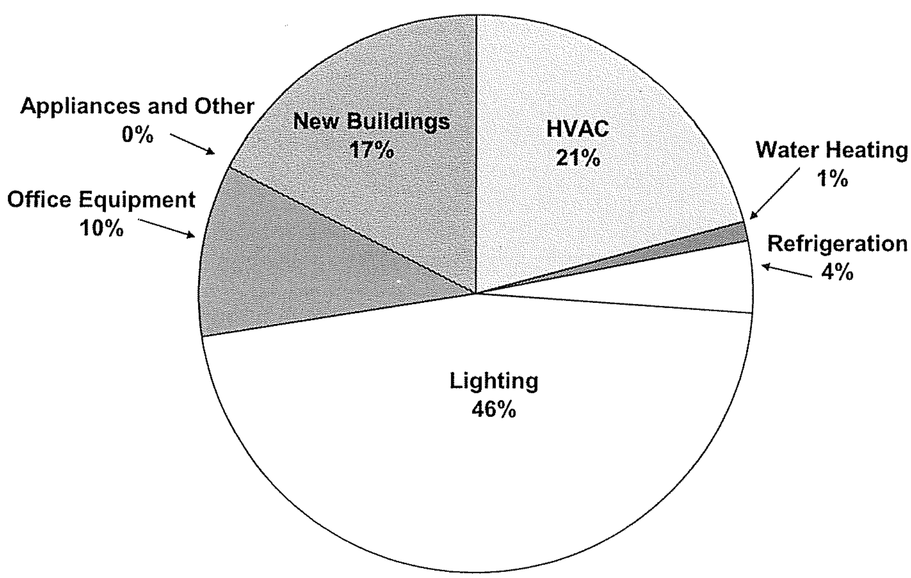
Table 4. Commercial Energy Efficiency Potential and Costs by End-Use

End-Use	Savings Potential in 2025 (GWh)	Savings Potential in 2025 (%)	% of Efficiency Resource Potential	Weighted Levelized Cost of Saved Energy ($/kWh)
Existing Buildings				
HVAC	3,993	5.9%	21%	$ 0.028
Water Heating	228	0.3%	1%	$ 0.033
Refrigeration	796	1.2%	4%	$ 0.017
Lighting	8,878	13%	46%	$ 0.011
Office Equipment	1,935	2.8%	10%	$ 0.003
Appliances and Other	13	0.0%	0%	$ 0.101
Subtotal	15,843	23%	83%	$ 0.015
New Buildings	3,348	4.9%	17%	$ 0.031
Total	**19,191**	**28%**	**100%**	**$ 0.018**

New, high-performance commercial buildings built today can cost-effectively reduce electricity consumption by 15 to 50% compared to building energy codes. As shown in Table 4, we estimate that efficient new buildings can reduce total electricity consumption by about 4.9% in 2025, which represents 17% of the total potential.

Figure 12. Commercial Energy Efficiency Potential in 2025 by End-Use in Virginia

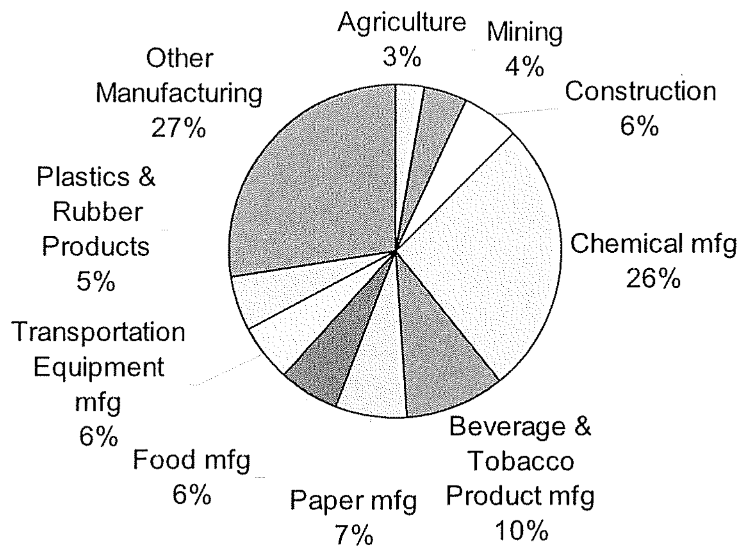
TOTAL: 19,191 GWh
28% of Projected Electricity Consumption in 2025



Industry

The industrial sector is the most diverse economic sector, encompassing agriculture, mining, construction and manufacturing. Because electricity use and efficiency opportunities vary by individual industry—if not individual facility, it is important to develop a disaggregated forecast of industrial electricity consumption. Unfortunately this energy use data is not available at the state level, so ACEEE has developed a method to use state-level economic data to estimate disaggregated electric use. This study drew upon national industry data to develop a disaggregated forecast of economic activity for the sector. We then applied electricity intensities derived from industry group electricity consumption data reported and the value of shipments data to characterize each sub-sector's share of the industrial sector electricity consumption (see Figure 13). Despite changes in economic activity and changes in energy intensity, there were few significant intra-sectoral shifts in energy consumption. As the figure shows, the largest industrial electricity consumers are the chemical, paper, and beverage/tobacco industries. Agriculture, mining, and construction are relatively minor electricity consumers compared to many other states, so they are not a major focus of this study.

Figure 13. Estimated Electricity Consumption for the Largest Consuming Industries in Virginia in 2008



We examined 18 electricity saving measures, 10 of which were cost effective considering Virginia's average industrial electric rate of $0.068 /kWh. These measures were applied to an industry specific end-use electricity breakdown. Table 5 shows results for industrial energy efficiency potential by 2025.

This analysis found economic savings from these cross-cutting measures of 3,726 million kWh or 18% of industrial electricity use in 2025 at a levelized cost of about $0.02 per kWh saved. This analysis did not consider process-specific efficiency measures that would be applied at the individual site level because available time, funding, and data did not allow this level of analysis. However, based on experience from site assessments by the U.S. Department of Energy and other entities, we would anticipate an additional economic savings of 5–10%, primarily at large energy-intensive manufacturing facilities. So the overall economic industrial efficiency resource opportunity is on the order of 23–28%. Therefore, the total economic potential for the industrial sector in 2025 would be about 5,152 GWh.

Table 5. Industrial Energy Efficiency Potential and Costs by Measure

Measures	Savings Potential in 2025 (GWh)	Savings Potential in 2025 (%)	% of Efficiency Resource Potential	Weighted Levelized Cost of Saved Energy ($/kWh)
Sensors & Controls	75	0.4%	2%	$0.01
Energy Information Systems	199	1.0%	5%	$0.06
Duct/Pipe insulation	663	3.2%	18%	$0.05
Electric Supply	618	3.0%	17%	$0.01
Lighting	310	1.5%	8%	$0.02
Total Motors	866	4.2%	23%	$0.03
Total Compressed Air	311	1.5%	8%	$0.00
Pumps	468	2.3%	13%	$0.01
Fans	133	0.6%	4%	$0.02
Refrigeration	84	0.4%	2%	$0.00
Total	**3,726**	**18%**	**100%**	**$0.02**

Combined Heat and Power

CHP provides substantial increases in overall fuel efficiencies by generating both thermal and electric power from a single fuel source. This co-generation approach bypasses most of the thermal losses inherent in traditional thermal electricity generation, where half to two-thirds of fuel input is rejected as waste heat. By combining heat and power in a single process, CHP systems can produce efficiencies of 70% or greater (Elliott and Spurr 1998).

For this report, Energy and Environmental Analysis (EEA), a division of ICF International, undertook an assessment of the cost-effective potential for CHP in Virginia. EEA identified about 322 MW from 9 operating CHP plants currently operating in the state.[7] The addition potential was estimated by assessing the electricity end-uses at existing industrial, commercial, and institutional sites across the Commonwealth and also considering sites that will likely be built in the future. These facilities would replace a thermal system (usually a boiler) with a CHP system that also produces power and that is primarily intended to replace purchased power that would otherwise be required at the site. Detailed information from this analysis is provided in Appendix E.

An additional application of CHP considered by this analysis is in the production of power and cooling though the use of thermally activated technologies such as absorption refrigeration. This application has the benefit of producing electricity to satisfy onsite power requirements and displacing electrically generated cooling, which reduces demand for electricity from the grid, particularly at periods of peak demand (see Elliott and Spurr 1998).

Three levels of potential for CHP were assessed (see Appendix E for detailed results):

- *Technical potential* represents the total capacity potential from existing and new facilities that are likely to have the appropriate physical electric and thermal load characteristics that would support a CHP system with high levels of thermal utilization during business operating hours.
- *Economic potential*, as shown in Table 6, reflects the share of the technical potential capacity (and associated number of customers) that would consider the CHP investment economically acceptable according to a procedure that is described in more detail in Appendix E.
- *Cumulative market penetration* represents an estimate of CHP capacity that will actually enter the market between 2008 and 2025. This value discounts the economic potential to reflect non-economic screening factors and the rate that CHP is likely to actually enter the market.

[7] This estimate excludes "qualifying facilities" under *Public Utility Regulatory Policy Act 1978*, Sec. 210. For a expanded discussion, see Elliott and Spurr (1998).

This potential is described in the energy efficiency policy scenarios, which are shown in the next section of the report.

Table 6. Economic Potential for CHP in Virginia by System Size

	50-500 kW	500-1,000 kW	1-5 MW	5-20 MW	>20 MW	All Sizes
Economic Potential	202	58	313	78	733	1,384

Examples of Energy Efficiency Programs

While an EERS target is independent of specific programs, there are many program designs that have proven successful over the past three decades. We present several of these program types below, along with specific examples of successful implementations that are drawn from ACEEE's report *Compendium of Champions: Chronicling Exemplary Energy Efficiency Programs from across the U.S.* (York, Kushler, and Witte 2008).

- ***Commercial/Industrial Lighting Programs***: Provide recommendations and incentives to businesses to increase lighting efficiency. Aiming to expedite the adoption of new technologies and decrease end-user's energy costs, the programs focus on marketing the most advanced lighting products and encourage greater efficiency in system design and layout. Xcel Energy's *Lighting Efficiency* program reached 4,346 participants, saving a total of 273 GWh during the years 2002-2006.

- ***Commercial/Industrial Motor and HVAC Replacement Programs***: Encourage the marketing and adoption of higher efficiency motors and HVAC equipment by offering rebates to distributors and end-users of qualifying equipment. Through monetary incentives and energy efficiency education, program advocates are shifting market tendencies away from a focus on initial equipment cost and toward an environment where lifecycle cost is increasingly considered by consumers. During 2006, Pacific Gas & Electric's *Motor and HVAC Distributor Program* saved a total of 16.55 GWh of electricity by offering $3.9 million in rebates.
- ***Commercial/Industrial New Construction Programs:*** Focus on training, educating, and providing financial incentives for architects, engineers, and building consultants to implement energy saving measures and technologies. By offering both prescribed and customizable incentive packages, these programs are able to influence a wide range of projects, which have in turn had the effect of raising the standards for energy efficiency in normal building practices. With its four distinct, yet combinable project "tracks," Energy Trust of Oregon, Inc.'s *Business Energy Solutions: New Buildings* program offers qualifying projects incentives of up to $465,000 each, which saved approximately 46.8 GWh of electricity and 1.2 million therms of natural gas through the end of 2007.
- ***Commercial/Industrial Retrofit Programs:*** With programs ranging from energy efficiency audits to financial assistance to even providing detailed engineering installation plans, Commercial/Industrial Retrofit Programs are designed to help implement cost-effective energy efficiency measures during new construction, expansion, renovation, and retrofit projects in commercial buildings. Programs focus on long-term energy management, peak load reduction, load management, technical analysis, and implementation assistance in order to give building owners and operators a better understanding of the energy related costs of, and potential savings for, their commercial buildings. Rocky Mountain Power and Pacific Power created approximately 100 GWh of gross electricity savings in Washington and Utah with their *Energy FinAnswer and FinAnswer Express* programs.

- ***Residential Lighting and Appliances:*** Headed by utility companies and energy nonprofits alike, Residential Lighting and Appliances Programs advocate the adoption of ENERGY STAR light bulbs, light fixtures, and home appliances through the use of rebates, marketing campaigns, advertising, community outreach, and retailer education. Lighting programs have focused on establishing and maintaining a customer base for compact fluorescent bulbs, in addition to fostering relationships between manufacturers and retailers in order to lower costs to the consumer. Appliance programs have sought to educate consumers on the long-term benefits of replacing aging, inefficient refrigerators, freezers, air conditioning units, and other large appliances with ENERGY STAR models, while providing an incentive to upgrade older models through rebates offered both for recycling old units and purchasing new ones. By selling 1.3 million CFLs during 2006 through its *Energy Star Residential Lighting Program*, Arizona Public Service anticipates saving a total of 360 GWh of electricity during the lifetime of the light bulbs. Additionally, the *California Statewide Appliance Recycling Program* recycled 46,829 aging appliance units in 2007, a measure that saved 33.3 GWh of electricity in 2006.

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- ***Residential Mechanical Systems Programs:*** Provide rebates and other financial incentives to contractors trained to properly install and service high-efficiency air conditioning, heat pumps, and geothermal heat-pump technologies. In addition to encouraging the purchase of energy-efficient appliances, these programs help to verify that existing equipment is appropriately installed and tuned in accordance with manufacturers' specifications, in order to optimize energy savings. Long Island Power Authority's *Cool Homes* Program has helped to introduce approximately 40,000 high-efficiency central cooling systems into the market, creating 29 GWh of annual electricity savings in 2006.
- ***Residential New Homes Programs:*** Provide incentives to builders who construct energy-efficient homes that achieve long-term, cost-effective energy savings. By addressing efficiency during the construction of homes and apartments, builders are able to maximize the financial and environmental benefits of efficient insulation, windows, air ducts, and appliances. Furthermore, ENERGY STAR certification provides developers with additional marketing strategies to attract buyers and renters. Some Residential New Homes programs also offer assistance to builders in developing efficiency objectives, and to potential buyers in locating efficient homes. With 100 participating residential builders and over 2,300 homes built to date, Rocky Mountain Power's *Energy Star New Homes Program* saved 3.4 GWh of electricity during 2006.
- ***Residential Retrofit Programs:*** With an emphasis on large scale systematic retrofits, Residential Retrofit Programs are designed to reduce electric and natural gas consumption and peak-time demand of residential buildings. Financial incentives, low-interest financing, and training are offered to residents and customers interested in assessing and improving their energy efficiency. From weatherization and duct sealing to installation of new technologies, proponents of Residential Retrofit Programs direct their efforts both to buildings with the highest energy usage and constituents with the greatest financial need. Since its inception in 1993, Vermont Gas Systems, Inc.'s *HomeBase Retrofit Program* has installed over 1,600 kWh in energy saving measures, contributing to over 77,000 Mcf of natural gas savings.

- ***Low-Income Programs:*** Seek to educate and assist qualifying participants in acquiring appropriate home weatherization, energy-efficient lighting and appliances, and other efficiency improvements. By helping limited income households increase their energy efficiency and reduce energy consumption, these programs in turn minimize long-term energy costs to customers. Through its *Appliance Management Program and Low-Income Services*, National Grid has reached over 40,000 customers, creating 42 GWh of annual energy savings.

ENERGY EFFICIENCY POLICY ANALYSIS

In this section, we outline three policy scenarios: a low, medium, and high case for energy efficiency policy and program implementation. Each scenario is comprised of a suite of energy efficiency policies and programs that are suggested for implementation or extension in Virginia and would begin to tap into the available energy efficiency resource potential described above. The more aggressive the scenario, the more the state takes advantage of its available, cost-effective resource potential. The three scenarios are shown in the matrix below (see Table 7) and the results of the scenarios are discussed next, including the estimated electricity and peak demand savings, and finally costs and electricity bill savings. Then we provide more detailed descriptions of the policies and assumptions under each policy scenario. For the recommended programs or supporting policies that aren't easily quantified in terms of energy impacts, we summarize what the efforts could look like but do not estimate energy impacts.

Table 7. Matrix of Energy Efficiency Policies and Programs in Low, Medium, and High Level Case Scenarios

	Scenario One: Low Case	Scenario Two: Medium Case	Scenario Three: High Case
Energy Efficiency Resource Standard (EERS) *	10% (of 2006 electricity use) by 2022	15% (of 2006 electricity use) by 2022; extend 1% per year target to 2025 (relative to prior-year sales)	19% (of 2006 electricity use) by 2022; extend 1.5% per year to 2025 (relative to prior-year sales)
Demand Response **	Low participation (10-20%) and curtailment (15-20%) rates and low (30%) backup generation potential	Medium participation (20-30%) and curtailment (20-30%) rates and medium (40%) backup generation potential	High participation (30-40%) and curtailment (25-40%) rates and high (50%) backup generation potential
Combined Heat & Power Supporting Policies	No supporting policies	Some incentives and removal of disincentives toward CHP	Expanded incentives and removal of disincentives toward CHP
Manufacturing Initiative	Limited activities	Expanded state manufacturing initiative	More aggressive state manufacturing initiative combined with economic development incentives
State Facilities	Current ESCO initiative	Expanded ESCO initiative	More aggressive ESCO initiative
Local Government Facilities	Current modest effort	Extend ESCO model to local level	More aggressive ESCO initiative
Building Energy Codes	IECC 2006 and ASHRAE 2004; update to IECC 2009	Adopt IECC 2012 (or 30% beyond IECC 2006)	Same as Scenario Two plus 50% by 2020
Appliance Efficiency Standards	Federal standards from EISA 2007, DOE revises standards to minimize lifecycle costs (LCC)	Same as Scenario One plus additional state standards	Same as Scenario Two
Energy Efficiency RD&D Initiative	None	None	Energy efficiency RD&D initiative
Consumer Education and Outreach***	SCC-directed initiative	Expanded SCC-directed initiative	Same as Scenario Two
Low-Income Efficiency Programs***	Current policies	Expanded low-income programs	Same as Scenario Two

* CHP and manufacturing initiative are included in the EERS.
**The assessment of demand response potential is covered in the next chapter and in Appendix D.
*** These policies/programs are included in the policy recommendations, though ACEEE does not estimate costs and electricity impacts.

Energy Efficiency Policy Scenario Results

This section describes results for each of the energy efficiency policy scenarios, including estimated electricity savings and peak demand impacts from efficiency in 2015 and 2025. Descriptions of the policies and recommendations are provided next and more detailed results are shown in Appendix B. The demand response potential, impacts on peak demand, and policy recommendations are covered in the next section of the report and in Appendix D.

Scenario 1—Low Case Energy Efficiency

The estimated electricity savings under the low case scenario are shown by policy/program in Table 8. Under this scenario, Virginia sets a savings target, or EERS, of 10% (of 2006 electricity consumption) by 2022, which is equivalent to a savings of about 11,000 GWh. Accounting for savings from building code upgrades and federal appliance standards under this low case scenario, Virginia is estimated to reduce forecasted electricity consumption in 2025 by 12% and reduce peak demand by 11%. Estimated summer peak demand reductions are shown by sector in Table 9. This scenario represents total electricity savings equivalent to about 38% of the cost-effective resource potential identified in ACEEE's analysis.

Table 8. Low Scenario: Summary of Electricity Savings by Policy or Program

Annual Electricity Savings by Policy (GWh)	2015	2025	Total Savings in 2025 (%)
Energy Efficiency Resource Standard (EERS)	4,791	10,656	7%
Building Energy Codes	379	1,354	1%
Appliance Efficiency Standards (Federal)	2,147	4,741	3%
Total Savings	7,317	16,750	12%
Adjusted Electricity Load Forecast (GWh)	119,516	127,445	
Savings (% Reduction in Reference Case)	6%	12%	

Table 9. Low Scenario: Summary of Summer Peak Demand Reductions by Sector (MW)

Sector	2015	2025	Total Savings in 2025 (%)
Residential	644	1,479	5%
Commercial	751	1,735	5%
Industrial	176	391	1%
Total	1,572	3,606	11%
% Reduction in Reference Case	5.5%	11.0%	

Scenario 2—Medium Case Energy Efficiency

In the medium scenario, Virginia meets a more aggressive energy savings target (EERS), adopts more aggressive building codes, and establishes additional programs and policies to pursue more energy efficiency in the Commonwealth. Table 10 provides a summary of the annual electricity savings by policy for 2015 and 2025 and the percent savings relative to the reference case electricity forecast.

Compared to the total cost-effective energy efficiency resource available in 2025, discussed in the previous section and shown in Table 2, this policy scenario represents the penetration of about 63% of the available energy efficiency potential by 2025.

Table 10. Medium Scenario: Summary of Electricity Savings by Policy or Program (GWh)

Annual Electricity Savings by Policy (GWh)	2015	2025	Total Savings in 2025 (%)
Energy Efficiency Resource Standard (EERS)	6,477	18,437	13%
*CHP Incentives (included in EERS)**	*504*	*1,394*	*1%*
*State Manufacturing Initiative (included in EERS)**	*850*	*2,883*	*2%*
State Facilities	205	497	0.3%
Local Government Facilities	409	994	0.7%
Building Energy Codes	595	2,821	2%
Appliance Efficiency Standards (Federal)	2,147	4,741	3%
Appliance Efficiency Standards (State)	125	425	0%
Total Savings	9,957	27,914	19%
Adjusted Electricity Load Forecast (GWh)	116,876	116,281	
Savings (% Reduction in Reference Case)	8%	19%	

Savings from these policies are included in the EERS, though we show here their contribution to the savings targets.

Table 11 shows estimated peak demand impacts from improved efficiency in this scenario. In total, efficiency policies and programs alone are estimated to reduce summer peak demand by 18% by 2025, relative to forecasted peak demand. These "permanent" peak impacts from efficiency are in addition to peak reductions from demand response efforts, which are discussed in the next section of the report and in Appendix D.

Table 11. Summary of Summer Peak Demand Reductions from Efficiency by Sector (MW)

Sector	2015	2025	Total Savings in 2025 (%)
Residential	784	2,153	7%
Commercial	1,194	3,318	10%
Industrial	191	577	2%
Total	2,169	6,048	18%

Scenario 3—High Case Energy Efficiency

The high case scenario represents a more aggressive effort for each of the policies analyzed in the medium scenario with the addition of a research, development, and deployment (RD&D) initiative. As shown in Table 12 and 13, under this scenario we estimate electricity savings of about 39,000 GWh by 2025, or a 27% reduction in forecasted electricity consumption, and a peak demand reduction of more than 8,000 MW in the same year, equivalent to a 25% reduction in forecasted peak demand. Again, these "permanent" peak demand reductions from efficiency are in addition to the potential for peak reductions from demand response. The high case scenario represents the penetration of 88% of the energy efficiency resource potential by 2025.

Table 12. Scenario 3: Summary of Electricity Savings by Policy or Program

Annual Electricity Savings by Policy (GWh)	2015	2025	Total Savings in 2025 (%)
Energy Efficiency Resource Standard	7,948	25,748	18%
*CHP Incentives (included in EERS)**	*1,572*	*3,829*	3%
*State Manufacturing Initiative (included in EERS)**	*925*	*3,467*	2%
State Facilities	307	746	1%
Local Government Facilities	614	1,491	1%
Building Energy Codes	424	2,884	2%
Appliance Efficiency Standards (Federal)	2,147	4,741	3%
Appliance Efficiency Standards (State)	125	425	0.3%
Energy Efficiency RD&D Initiative	29	3,083	2%
Total Savings	11,593	39,117	27%
Adjusted Electricity Load Forecast (GWh)	**115,240**	**105,078**	
Savings (% Reduction in Reference Case)	**9%**	**27%**	

*: *Savings from these policies are included in the EERS, though we show here their contribution to the savings targets.*

Table 13. Summary of Summer Peak Demand Reductions by Sector (MW)

Sector	2015	2025	Total Savings in 2025 (%)
Residential	879	3,006	9%
Commercial	1,322	4,520	14%
Industrial	233	779	2%
Total	2,435	8,306	25%

Discussion of Policies

This section describes each of policies recommended and provides the assumptions used in the analysis for each scenario.

Energy Efficiency Resource Standard

An Energy Efficiency Resource Standard (EERS) is a quantitative, long-term energy savings goal for utilities or other entities (often coupled with a peak demand reduction target). Currently eighteen states have adopted some form of an EERS or have established legislation directing a state agency to set an energy savings target. This approach contrasts with many earlier state-legislated targets that were set in terms of funding levels or were short term. EERS targets are typically set independently of specific program, technology, or market targets in order to give utilities maximum flexibility to find the least-cost path toward meeting the targets (Nadel et al. 2006; ACEEE 2008).

Virginia has been among the leading eighteen states. In the spring of 2007, Governor Timothy Kaine inserted an enactment clause into the electricity "re-regulation" legislation (S.B. 1416) that directed the SCC to review a goal of reducing electricity use by 10% (of 2006 consumption) by 2022. The SCC was directed to review this possible energy savings target and make recommendations to the General Assembly. Our review of the various documents and interviews with leaders in the state suggest that some ambiguity exists as to the quantitative value of the savings target and whether the target is mandatory. The state needs to clarify this target. We also suggest that a companion peak demand reduction target should be set capturing both the permanent demand reductions from efficiency as well as the savings from demand response programs, as is discussed later in this report.

For our low case energy efficiency scenario, we assume that the Commonwealth establishes the 10% goal by 2022 discussed above as a binding target. This target applies to all electric providers—investor-owned utilities, municipal utilities, and rural electric cooperatives—though we would suggest that the coops and municipals should have a somewhat lower target because of their customer mix. Readers should note that a 10% savings of 2006 electricity use is equivalent to savings of about

11,000 GWh. Relative to 2022 *forecasted* consumption in the reference case (139,000 GWh) an 11,000 GWh reduction is equivalent only to an 8% reduction. In this low case scenario, savings do not extend past the 2022 target.

In our medium case energy efficiency scenario, we propose that Virginia sets a binding target of reducing electricity use 15% (of 2006 consumption) by 2022 and extends it to 2025 at an annual savings target of about 1% (relative to prior-year sales). Again, readers should note that a 15% savings target of 2006 electricity consumption (about 16,000 GWh) is equivalent to only a 12% reduction in *forecasted* consumption for 2022. By extending the target to 2025, savings grow to more than 18,000 GWh (see Table 10). In 2025, the EERS savings are equivalent to about a 13% reduction in reference case electricity consumption.

Savings to meet the EERS goals come from each of the three sectors, and various energy efficiency programs could contribute savings toward the target. For example, we estimate that the manufacturing initiative and CHP incentives, which are discussed next, contribute savings of about 3,100 GWh, or 17%, of the total 2025 savings target. These program savings come from a combination of both commercial and industrial sector efforts, contributing to 28% of the combined goals for these sectors alone.

Finally, our high case scenario assumes that an EERS sets binding annual savings targets (relative to prior-year sales) starting at 0.25% in year one, ramping up to 1.5% per year by year six, and extending to 2025 at the 1.5% per year target. This scenario is equivalent to a 19% savings target (of 2006 electricity consumption) by 2022. Under this scenario, total savings by 2025 reach nearly 26,000 GWh, which is equivalent to an 18% reduction in electricity consumption in the reference case.

Expanded State Manufacturing Initiatives

Based on discussions with a broad range of stakeholders involved with the manufacturing sector in Virginia, we propose a government/industrial collaborative we are calling the "Virginia Manufacturing Initiative." The goal of the initiative would be to address the three key barriers to expanded industrial energy efficiency identified by the stakeholders: the need for assessments that identify energy efficiency opportunities; access to industry-specific expertise; and the need for an expansion of the trained manufacturing workforce with energy efficiency experience.

The initiative would establish Centers of Excellence in the model of the U.S. Department of Energy's Industrial Assessment Center (IAC)[8] program, where university engineering students are trained to conduct energy audits at industrial sites. Centers could be established at the two main technical universities in Virginia, Old Dominion University (ODU) and Virginia Polytechnic Institute and State University (Virginia Tech). Expanding beyond the IAC model, these centers would partner with local community colleges and trade schools to bring their students into the larger network centered around the local Center of Excellence. These nearby satellite centers would extend training and associated materials to trade school and community college partners, and offer the opportunity to join the audits they conduct. The Virginia Philpott Manufacturing Extension Partnership (VPMEP) offers a connection to other regional educational centers that can provide outreach to manufacturing companies that might not otherwise be aware of energy efficiency programs.

This system would benefit three key groups: students interested in working in industrial energy management; businesses that need reliable, knowledgeable, and affordable consultation with regard to their energy usage; and the educational facilities and VPMEP outreach efforts that connect Virginia's manufacturers to the wealth of knowledge and proficiency that resides in the state.

IAC program and implementation results recorded over the last 20 years show that this program could identify 10-20% electricity savings per facility and achieve a 50% implementation rate. The

[8] For more information on the IAC program, visit: http://iac.rutgers.edu/.

number of audits per year would ramp up from 50 in the first year to 100 in the second and 200 in the third year and each following year. We calculate these 200 audits would represent roughly 10% of manufacturing energy use in Virginia. Because of time lag between the audit and implementation, we assume that investment and savings for each year would occur over three years, while program costs would begin in year zero. Program costs for the IAC program are about $1 for every $10 saved by industry. We factor in another $0.25 per $10 saved to account for additional education costs.

In the high case scenario, we expanded the number of assessments provided by the centers and complement these program offering with economic development incentives. As in many states, Virginia offers economic development incentives designed to encourage business owners to make improvements and invest in their facilities. Investments in energy efficiency count as applicable investments for many of these programs in Virginia. The *Virginia Economic Development Partnership* does look at energy efficiency investments as capital improvements for its purposes, and thus they are eligible for such incentives. Similarly, the *Virginia Small Business Financing Authority*, which helps provide financing for large capital investment projects, also considers efficiency investments as eligible. These incentives include grants and loans for the capital improvements.

There are complementary policies that could leverage economic development programs to reduce Virginia's energy consumption:

- The Virginia Department of Housing and Community Development administers the state's *Enterprise Zones* (EZs), which encourage companies to invest in their properties to enhance their competitiveness, and focuses specifically on economically distressed areas. Businesses located within EZs can take advantage of the Real Property Investment Grant, which offers a cash grant of up to $250,000 for investment projects, including investments in energy efficiency improvements. Since EZs have strong workforce development requirements, encouraging businesses to participate in their local EZs by making energy efficiency investments can help create jobs as well.

- These programs can all be leveraged to help Virginia achieve the energy efficiency goals that might be set by an EERS. Virginia's economic policies are beginning to encourage energy efficiency: in 2007, the Virginia State Legislature passed a bill (S.B. 1051) allowing buildings that exceed the state's energy efficiency standards by 30% to be taxed at a lower rate than typical buildings. Each individual taxing locality must decide whether or not to create a special tax bracket for these efficient buildings. But to date, it appears that very few have done so. Virginia could be more aggressive in encouraging efficiency and spreading the word to the public that such investments are critical to the state's energy future.

- Designating areas as Energy Improvement Districts (EIDs) are one way that some cities have steered companies toward the energy efficiency investments that ultimately positively impact their bottom lines. EIDs can take many forms, but foremost in their design is the provision of both financial and technical assistance that businesses require as they prepare to think about making investments in energy efficiency. And some EIDs pool money together from participating companies to purchase large distributed generation systems and then share the energy created by the systems, as well.

Prioritizing energy efficiency in economic development schemes makes sense because energy efficiency can help companies become more profitable and thus increase their levels of employment and investment. Furthermore, Virginia is a highly business-friendly state, and has an economic development infrastructure that is strong and well connected to the business community. Using Virginia's multiple economic development entities to market and/or administer energy efficiency programs is one way that Virginia can get a head start on helping companies make the efficiency investments necessary to meet any EERS goals.

Combined Heat and Power Incentives

Experience over the past decade has shown that if a level playing field is created for CHP, it will thrive, as has been seen in Texas (Elliott et al. 2007b). ACEEE has identified five factors that contribute to creating a favorable market for CHP:

- Standard interconnection rules;
- CHP-friendly standby rates;
- CHP financial incentive programs;
- Output-based emissions regulations (OBR); and
- Inclusion of CHP/waste heat recovery in a state RPS or EERS.

While interconnection guidelines are pending in the state (according public documents released by the Virginia State Corporation Commission's Division of Economics and Finance), the state otherwise has not actively supported CHP. This lack of policies effectively discourages CHP because it creates greater hurdles to deployment and thus adds to the overall project costs and timelines. Currently in Virginia there are only 9 operating CHP plants totaling 322 MW of capacity (see Appendix E for more details). We suggest that Virginia undertake a review of regulatory policies and work to encourage the appropriate authorities to move forward with policies that will foster a friendlier environment for CHP.

There are several areas in which state-level agencies could work to encourage greater CHP deployment:

1. *Interconnection*—The first is to establish standard interconnection rules that explicitly outline the steps required to interconnect CHP systems to the electric grid. According to the Virginia State Corporation Commission's Division of Economics and Finance, the state is considering interconnection rules for distributed generation, which often includes CHP. For interconnection rules to encourage CHP, they typically delineate particular system size categories, and combine particular review processes and fees that scale up as system sizes increase. They also explicitly name CHP as an eligible group of technologies, and provide system owners with a list of simple, transparent steps and easily navigable forms to apply for interconnection with the local utility. Some states also list specific manufacturers and models of CHP systems that have been approved for interconnection.

2. *Incentives*—Secondly, Virginia could develop incentives that encourage the deployment of distributed generation such as CHP. Some states shape these incentives as favorable property tax treatment, which are allocated to the portion of the property covered by a CHP system. Other states provide sales tax incentives based upon the size and output of CHP systems. These of course help reduce the overall cost of operating a CHP system and thus work to encourage deployment.

3. *Output-Based Emissions Regulations*—To encourage CHP deployment, many states also develop output-based emissions regulations (OBR), as opposed to emissions regulations based upon fuel input. OBRs take into account the fact that CHP systems produce more useful energy with their fuel inputs than other systems, and so give credit to the useful thermal output produced by CHP systems. Total emissions are calculated based upon system output, as opposed to fuel input. In this way, OBRs encourage CHP deployment.

4. *Include CHP in EERS*—Finally, states that wish to encourage deployment of CHP and other forms of clean distributed generation often include these technologies as eligible resources for their Renewable Portfolio Standards or EERS (discussed above). Allowing highly efficient CHP systems to explicitly count towards the proposed Virginia EERS would also increase the deployment of CHP.

These steps, which will lead to regulatory certainty, will reduce the effective cost of CHP projects. In the medium efficiency policy scenario, we project that these steps will reduce the effective cost of

CHP projects by $500/kW installed. Based on the market penetration scenario of EEA's analysis, a $500/kW incentive can result in additional CHP peak demand capacity of about 240 MW by 2025, equivalent to 1,400 GWh or a 1% reduction in overall electricity consumption.

CHP also represents a low cost source of efficiency reductions, particularly in the commercial sector. We thus suggest that utilities be encouraged to participate in encouraging expanded CHP, which could lead to a $1,000/kW reduction in cost through project funding participation. As a result, we suggest that we could see 570 MW of peak demand capacity in this scenario with the $500/kW installed implicit cost reduction. This is equivalent to a 3% reduction in overall electricity consumption in 2025.

State and Local Facilities

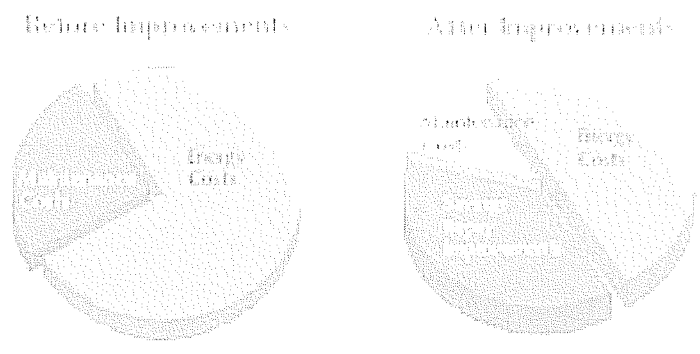
Government facilities represent unique opportunities for Virginia to implement energy-efficient practices saving the tax payers money while leading by example in advancing efficiency as Virginia's "first fuel." The Commonwealth has nearly one hundred facilities that report energy consumption costs to the Department of Mines, Minerals, and Energy (DMME). Virginia incorporates several different programs in order to promote efficiency among its agencies, including energy service performance contracting (ESPC) (Walz 2008).

The Federal Government and a number of other states use ESPCs to implement energy efficiency projects. An Energy Service Company (ESCO) can serve a number of needs in a project, including:

- Identifying and evaluate the energy savings opportunities;
- Developing the technical details of the project;
- Managing the design, installation, and commissioning;
- Arranging financing, though in some case the state may play this role (Birr 2008);
- Training staff and provide maintenance services; and
- Guaranteeing the savings will cover the project costs (KCC 2008).

The energy savings are used to repay this project cost as shown in Figure 14 (KCC 2008; Birr 2008). This model has proven highly effective in many places both in terms of delivering energy savings and in terms of cost effectiveness (Hopper, Goldman, and McWilliams 2005).

Figure 14. Graphical Representation of How an ESPC Project Is Financed



Source: KCC (2008)

The key to the success of these projects is to bring together a project structure that can facilitate all aspects of the program, as is the case in Pennsylvania. Under that program, approximately three full-time equivalent staff supported by an experienced contractor:

1. Pre-qualifies ESCOs that can participate in the program;
2. Reviews and negotiates the terms of the ESPC agreements since the government facilities

do not have the expertise to evaluate either the technical or contractual aspects of these projects; and

3. Reviews the completed projects to ensure that the projects are performing as agreed to in the contract.

Pennsylvania has been able to manage almost 50 projects each year, with total program and administrative costs of less than 2% of project costs (PA-GSA 2008; Birr 2008).

Virginia's EPSC program might be strengthened when compared to leading states such as Pennsylvania, Kansas, and Colorado, since it reaches only a portion of state facilities. A more robust structure and additional technical support might also be engaged. State agencies participate in efficiency programs, so significant additional energy efficiency opportunities still exist that could increase savings in state facilities. To address these opportunities, we recommend that Virginia expand its program, modeling the restructured program around the Pennsylvania experience drawing upon an expert consultant to complement the state agency staff (PA-GSA 2008). We also recommend that the Commonwealth draw upon a national organization that has been formed with DOE support, the *Energy Services Coalition,*[9] which supports state and other entities in implementing ESPC programs (ESC 2008).

We also suggest that the program be extended to local government facilities. We understand that local governments can encounter bond rating problems with ESPC contracts because the rating entities view them as unsecured loans. To address this problem, the state should consider establishing a bonding authority that would finance these EPSC projects, with the project funding paid back by the energy savings.

Based on this model, we assume that state and municipal buildings in Virginia can achieve an average of a 20% reduction in projected 2025 electricity sales, with a 50% participation rate in the medium case policy scenario. In the high case scenario, we assume a 75% participation rate by 2025. We assume the average investment costs are consistent with the projected efficiency resource cost for the commercial sector identified in this report and that the program and administrative costs including evaluation, measurement, and verification are 2% of project cost, somewhat higher than for the Pennsylvania General Service Administration program (Birr 2008). Under these assumptions, we estimate savings in the medium case of about 600 GWh by 2015 and about 1,500 GWh by 2025 from state and local facilities, or a 1% reduction in electricity consumption in 2025. In the high case scenario, savings grow to 2,200 GWh by 2025, a 1.5% reduction in projected electricity consumption.

Building Energy Codes

Building energy codes are a foundational policy to ensure that efficiency is integrated into new buildings in Virginia. If efficiency is not incorporated at the time of construction, the new building stock represents a "lost opportunity" for energy savings because efficiency is otherwise difficult or expensive to install after a building is built.

In 2008, Virginia will add an estimated 30,000 homes or 1% to its existing housing stock of about 3 million (Economy.com 2008). This is a downturn from recent annual additions of about 2% of the housing stock (2000-2006), though still represents the largest source of growth in home energy usage and therefore a critical opportunity for increased energy efficiency in the Commonwealth. New commercial buildings are expected to be built at a similar pace to residential homes based on forecasted employment (Economy.com 2008).

Virginia, which recently adopted the International Energy Conservation Code 2006, has already begun efforts to review the IECC 2009 and is likely to adopt it, going into effect in 2011 (Rodgers 2008). For this analysis, we modeled the following scenarios:

[9] For more information on the Energy Services Coalition, see http://www.energyservicescoalition.org /about/index.html.

- In our low case scenario, IECC 2009 is adopted in 2009, effective in 2011, reducing energy usage 15% in new residential and non-residential buildings compared to the 2006 IECC and ASHRAE 90.1-2004. This scenario would result in savings of about 1% of projected electricity sales in 2025.
- In our medium case scenario, a second new state code, the IECC 2012, is adopted and goes into effect in 2015, reducing energy use by 30% from 2006 IECC and ASHRAE 90.1-2004. The 30% reduction is ASHRAE's savings target for the 90.1-2010 code. A proposal for 30% savings in residential buildings is now pending before the IECC. Adopting IECC 2012 would generate about 2,800 GWh of electricity savings, or 2% of projected electricity sales in 2025.
- Our high case scenario builds upon our medium case scenario to include the adoption of a new state code that becomes effective in 2020, reducing building energy use by 50% relative to 2006 IECC and ASHRAE 90.1-2004. This would yield savings of nearly 2,900 GWh in 2025.

The new building codes require a commitment by the state to enforce the higher standards. We assume enforcement of each code starts at 70% compliance in the first year, 80% in second year, and 90% in the third and subsequent years.

Appliance Efficiency Standards

Lighting and appliance standards, first authorized by Congress in the 1970s and legislated again in 1987, 1992, 2005, and 2007, have become a core energy policy for the United States, setting performance targets for dozens of common household and business products and systems. Individual states have played and continue to play an important role in advancing standards for the nation. In the 1980s, states' initiative in developing standards in the face of federal inaction led to the landmark National Appliance Energy Conservation Act of 1987 (NAECA). Since then, state enactment of standards on products not covered by federal law has led to many new federal standards.

In the low case scenario, we account only for savings from appliance standards that result from recent federally legislated appliance standards. These include standards set by the Energy Independence and Security Act of 2007 (EISA) and those that DOE are directed to establish. ACEEE estimated savings from about 30 products to determine the reduced electricity consumption attributed to the implementation of federal appliance standards (ASAP 2008). However, savings will not begin to accrue until 2010 for the vast majority of these products as the standards are not set to take effect until that date. Savings from federal appliance standards alone will reduce electricity consumption by about 2,150 GWh by 2015 and 4,700 GWh by 2025, or 3.3% of electricity sales in 2025.

In the medium and high case scenarios, we examined the additional savings that Virginia could realize should it choose to implement appliance standards on products beyond those covered by federal legislation. In estimating savings for these two scenarios, ACEEE analyzes appliance standards for an additional six products which would reduce consumption by an additional 125 GWh in 2015 and 425 GWh in 2025, or 0.3% of electricity sales in 2025 (ASAP 2008). In our medium and high case scenarios, total savings amount to about 2,300 GWh in 2015 and 5,200 GWh in 2025, or 3.6% of forecasted electricity sales in 2025.

Research, Development, and Deployment (RD&D)

Several states support active research, development, and deployment (RD&D) programs designed to develop technologies appropriate to each state's climate, economy, and other resources. For more information, see the Association for State Energy Research and Technology Transfer Institutions (www.asertti.org). In the high case energy efficiency policy scenario, we assume a policy initiative that establishes a state RD&D entity to undertake Virginia-specific research into energy efficiency technologies and to help develop energy efficiency jobs and businesses in Virginia. In order to meet long-term savings goals, RD&D of new technologies is critical to sustain continued improvements in energy efficiency after currently commercialized technologies and practices are widely adopted.

Based on successful programs in New York and other states, we estimate that an RD&D effort in Virginia could reduce electricity consumption by about 3,000 GWh in 2025, or 2% relative to the reference case.

Consumer Education and Outreach

The majority of policies discussed in this report will require a few years to come to fruition. To catalyze efficiency efforts in the state, we recommend that Virginia consider engaging in a public education initiative to encourage energy-saving practices. The SCC has been directed to look into providing this service to the public. This could be accomplished through a wide array of media to promote calls by the governor for investments in energy efficiency and conservation. ACEEE modeled a program for Florida that was based on an existing short-term public outreach program in California and found that Florida could save 3% of projected electricity sales and 5% of peak demand in 2010 with such a program.[10] These public action programs are by their nature of limited duration, being effective for a few years at most. As a result, significant savings were realized in the first few years but quickly dissipated thereafter. While the direct impacts of these efforts may have limited long-term impact, sending signals to consumers and supplying them with information about efficiency programs establishes a solid foundation for the introduction and efficacy of these and other policies.

Public education should also be an integral part of any long-term efficiency program efforts. The states with the most effective programs typically invest in significant communications efforts, where leaders including the governor appear prominently in public media. The value of leadership in this regard cannot be overstated.

Low-Income Efficiency Programs

Addressing the energy needs of low-income households is crucial when implementing efficiency programs as these households on average spend a greater percentage of their income on energy relative to their wealthier counterparts. Programs like the Low-Income Home Energy Assistance Program (LIHEAP) provide households with additional funds they can put towards paying energy bills or making efficiency improvements to their homes. ACEEE recognizes this need and recommends that Virginia consider implementing its own low-income assistance programs to assuage these households' economic concerns, especially in the wake of rising fuel costs.

Although short-term relief is important, funding energy bills without concomitantly promoting and implementing efficiency measures precludes any long-term benefits, meaning that more state and local funds will be consumed than is necessary since household energy bills will not fall in the future. Thirteen percent of Virginians heat their homes with oil and 34% heat their homes with natural gas (EIA 2003), so these households, especially those occupied by low-income households, are particularly vulnerable to high fuel costs. Focusing on home weatherization programs provides short-term and, more importantly, long-term benefits, guaranteeing that future energy bills will drop and remain low. These programs can also incorporate educational and job training components, which inform the public on how to maximize their energy savings while giving individuals the knowledge and skills to take these ideas and diffuse them throughout their communities.

We also recommend introducing programs for middle-income households that do not qualify for low-income assistance, as high fuel costs have a substantial impact on their economic security as well. Programs like low cost financing allow households in this income bracket to afford efficiency improvements, like home weatherization. Locally focused efficiency suites can also have a

[10] In 2001, California and other Western states used such programs to achieve substantial savings and help weather their energy crisis with minimum disruptions. For example, an evaluation of the California program found that it reduced energy use by 6.7% in the summer of 2001 and peak demand by about 11% relative to the year before (Global Energy Partners 2003). And significant benefits persisted for multiple years, especially as approximately 60% of the actions involved technology investments with a two-year payback. The Florida program was conservatively assumed to be only half as effective.

substantial impact on energy consumption, such as direct installation of energy-efficient products and the identification of homes requiring large-scale efficiency improvements. We assume that these types of programs would be part of the state EERS and, therefore, are not counted separately.

Costs and Benefits in Medium Case Energy Efficiency Policy Scenario

In this section, we estimate the costs and benefits of the medium case energy efficiency policy scenario to determine overall cost-effectiveness. There is no single answer to whether energy efficiency is cost-effective, but rather there are multiple perspectives analysts take to determine cost-effectiveness. Here, we examine the medium policy scenario using two cost-effectiveness tests, the Total Resource Cost (TRC) test and the Participant Cost test. We do not do an equivalent analysis for the demand response policy scenario, which is discussed in the next section, due to the difficulty in evaluating the dollar savings benefits to consumers from demand response measures.

The costs needed to run the efficiency policies and programs recommended for the medium scenario and achieve the estimated electricity savings include both the investments in efficient technologies or measures and the administrative or marketing costs to run programs and administer policies. The technology investments might include any combination of incentives paid to customers or direct customer costs. See Table 14 for a breakdown of the estimated costs in the medium scenario. See Appendix B for estimates of total costs in the low and high case scenarios.

Table 14. Annual Energy Efficiency Costs in Medium Scenario (Millions of 2006$)

	2010	2015	2020	2025
Customer Investments	$105	$414	$488	$483
Incentives Paid to Customers	$67	$132	$152	$148
Admin/Marketing Costs	$16	$30	$35	$36
Total Costs	$187	$575	$676	$668

Note: These costs are undiscounted and shown in real, 2006$.

The chapter on macroeconomic impacts uses these cost assumptions to estimate impacts of the efficiency policies on the economy, including overall benefits to customers. Here, we report a net present value (NPV) analysis of costs and benefits to society and to participants. The next two tables (see Table 15 and Table 16) show results from the TRC test and the Participant Cost Test, respectively, with a breakdown of total costs and benefits (present value in 2006$) by policy type and by sector over the study time period (2009–2025). Readers should note that although the study time period ends in 2025, savings from the efficiency measures persist over the lifetime of each specific measure. Accounting for these additional savings beyond the study time period would yield additional benefits and therefore a higher benefit/cost ratio.

The TRC test, as shown in Table 15, evaluates the net benefits of energy efficiency to the region as a whole. This test considers total costs, including investments in efficiency measures (whether incurred by customers or through incentives) and administrative or marketing costs. Benefits in the TRC test are the avoided costs of energy, or the marginal generation costs that utilities avoid by reducing electricity consumption through energy efficiency. The avoided energy resource costs were determined by the analysis by Synapse Energy Economics (see Appendix A). The TRC test, which shows an overall benefit-to-cost ratio of 1.9, suggests a net positive benefit to Virginia as a whole from implementing these efficiency programs and policies. When accounting for benefits over the lifetime of the efficiency measures, the ratio increases to 2.6.

The Participant Cost Test, as shown in Table 16, takes the perspective of a customer installing an energy efficiency measure in order to determine whether the participant benefits. The costs are the costs to customers for purchasing or installing energy efficiency and the benefits are the savings on customers' electricity bills due to reduced consumption plus any incentives paid to the customers. Again, this analysis only takes into account costs and benefits through 2025, even though customer savings on electric bills would continue well past 2025. Even without accounting for the benefits that persist after measures installed in 2025, the Participant Cost Test yields a positive benefit to participants, with a 2.4 benefit/cost ratio. If accounting for savings that persist over the measure lifetime, this ratio increases to 3.3.

See Figure 15 for a representation of the results using three different discount rates.

Table 15. Total Resource Cost (TRC) Test (2009–2025)

By Policy/Program	**NPV Costs**	**NPV Benefits**	**Net Benefit**	**B/C Ratio**
Energy Efficiency Resource Standard (EERS)	$ 3,468	$ 6,949	$ 3,481	2.0
*CHP Supporting Policies**	*$ 234*	*$ 530*	*$ 296*	*2.3*
*State Manufacturing Initiative**	*$ 541*	*$ 954*	*$ 413*	*1.8*
State Facilities	$ 57	$ 201	$ 143	3.5
Local Government Facilities	$ 114	$ 401	$ 287	3.5
Building Energy Codes	$ 604	$ 849	$ 245	1.4
Appliance Efficiency Standards	$ 1,393	$ 2,033	$ 640	1.5
Total	**$ 5,636**	**$ 10,433**	**$ 4,797**	**1.9**
By Sector	**NPV Costs**	**NPV Benefits**	**Net Benefit**	**B/C Ratio**
Residential	$ 2,734	$ 3,697	$ 963	1.4
Commercial	$ 2,092	$ 5,337	$ 3,246	2.6
Industry	$ 811	$ 1,398	$ 587	1.7
Total	**$ 5,636**	**$ 10,433**	**$ 4,797**	**1.9**

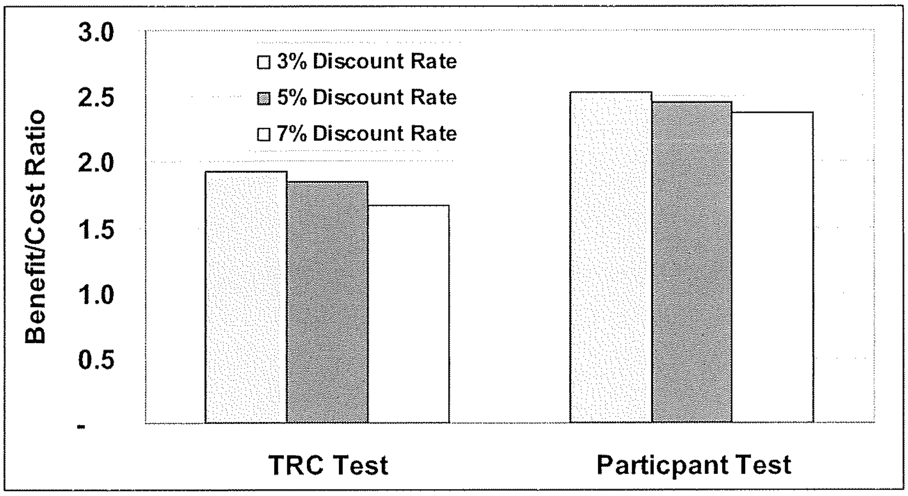
*Note: These two policies are included in the costs and benefits of the EERS.

Table 16. Participant Cost Test (2009–2025)

By Policy/Program	**NPV Costs**	**NPV Benefits**	**Net Benefit**	**B/C Ratio**
Energy Efficiency Resource Standard (EERS)	$ 3,159	$ 9,054	$ 5,895	2.9
*CHP Supporting Policies**	*$ 228*	*$ 719*	*$ 491*	*3.1*
*State Manufacturing Initiative**	*$ 523*	*$ 781*	*$ 258*	*1.5*
State Facilities	$ 56	$ 224	$ 168	4.0
Local Government Facilities	$ 112	$ 447	$ 335	4.0
Building Energy Codes	$ 591	$ 975	$ 384	1.7
Appliance Efficiency Standards	$ 1,392	$ 2,285	$ 894	1.6
Total	**$ 5,310**	**$ 12,985**	**$ 7,675**	**2.4**
By Sector	**NPV Costs**	**NPV Benefits**	**Net Benefit**	**B/C Ratio**
Residential	$ 2,547	$ 5,289	$ 2,742	2.1
Commercial	$ 1,973	$ 6,493	$ 4,520	3.3
Industry	$ 790	$ 1,203	$ 413	1.5
Total	**$ 5,310**	**$ 12,985**	**$ 7,675**	**2.4**

*Note: These two policies are included in the costs and benefits of the EERS.

Figure 15. Results of TRC and Participant Cost Tests Using Three Discount Rates



ASSESSMENT OF DEMAND RESPONSE POTENTIAL

This section defines Demand Response (DR), assesses current DR activities in Virginia, uses benchmark information to assess DR potential in Virginia, and concludes with policy recommendations that could foster DR contributing appropriately to the resource mix in Virginia that can be used to meet electricity needs. Potential load reductions from DR are estimated for a suite of DR programs that represent the technologies and customer types that span a range of DR efforts (as is discussed below and in Appendix D.

Defining Demand Response

DR focuses on shifting energy from peak periods to off-peak periods and clipping peak demands on days with the highest demands. Within the set of demand-side options, DR focuses on clipping peak demands that may allow for the deferral of new capacity additions and enhance operating reserves to mitigate system emergencies. Energy efficiency focuses on reducing overall energy consumption with attendant permanent reductions in peak demand growth. Taken together, these two demand-side options can provide opportunities to more efficiently manage growth, provide customers with increased options to manage energy costs and represent an important element that can be integrated into least-cost resource plans.

DR resources are usually grouped into two types: (1) load-curtailment activities where utilities can "call" for load reductions; and (2) price-based incentives that use time-differentiated and/or dispatchable rates to shift load away from peak demand periods and reduce overall peak-period consumption. Interest in both types of DR activities has increased across the country as fuel input prices have increased, environmental compliance costs have become more uncertain, and electric systems face the substantial investment in overall electric infrastructure needed to support new generation resources.

The summary of DR potential presented in Table 17 focuses on load-curtailment and backup generation and does not include savings resulting from price-based incentives. Residential load-curtailment typically involves direct load control (DLC) of air conditioners—although this can also cover appliances—as well as temperature offsets, which increase thermostat settings for a certain period of time. Commercial and industrial applications of DR focus on load control of space conditioning equipment; however, this depends on customer size: self-activated load reductions are usually more prudent for larger customers. Backup generation for commercial and industrial applications involves generators with start-up equipment that allows them to come online with short notice from utilities, relieving the additional demand on the system during peak hours.

Rationale for Investigating Demand Response

DR alternatives can be implemented to help ensure that a utility continues to provide reliable electric service at the least cost to its customers. Specific drivers often cited for DR include the following:

- **Ensure reliability**—DR provides load reductions on the customer side of the meter that can help alleviate system emergencies and help create a robust resource portfolio of both demand-side and supply-side resources that meet reliability objectives.
- **Reduce supply costs**—DR may be less expensive per megawatt than other resource alternatives.
- **Manage operational and economic risk through portfolio diversification**—DR capability is a resource that can diversify peaking capabilities. This creates an alternative means of meeting peak demand and reduces the risk that utilities will suffer financially due to transmission constraints, fuel supply disruptions, or increases in fuel costs.
- **Provide customers with greater control over electric bills**—DR programs would allow customers to save on their electric bills by shifting their consumption away from higher cost hours and/or responding to DR events.
- **Address legislative/regulatory interest in DR**—Electric utility legislation enacted in April 2007 set a statutory goal for the Commonwealth to save 10% of its total 2006 electricity sales by 2022 (H.B. 3068 and S.B. 1416, commonly referred to as the electricity "re-regulation" legislation). While the legislation focuses on an energy consumption goal, the Virginia State Corporation Commission Energy Efficiency Working Group has stated that reducing peak demand is also an important consideration (SCC 2008c).

Commonwealth of Virginia—Background

Virginia's service territory is characterized by high population and load growth, the majority of which is attributable to new residents. Since 2000, the Commonwealth has grown in population by 8%, compared to 6% for the United States as a whole. The impact of population growth on electricity demand is compounded by the fact that *electricity consumption per customer* has risen dramatically in the past several decades. PJM projects that the peak demand for electricity in Dominion's service area will grow by almost 1,800 MW in just five years—the equivalent, in PJM's estimation, of adding one million homes to the system. Dominion's own studies project it will need 4,000 MW of new capacity in ten years. This growth will strain Virginia's electric system (Dominion 2008).

Virginia has had some of the lowest electricity rates in the county and, until recent years, has had adequate capacity to meet the Commonwealth's electricity needs. As a result, interest in energy efficiency and DR in Virginia has been limited. Current conditions are changing. New capacity and infrastructure investments are needed. Increasing electricity costs stem from a combination of rising consumption (necessitating new investment in generation and transmission), increases in fuel costs, and the potential for additional environmental restrictions. The elimination of price caps and potentially higher fuel prices will increase the importance of assessing future resources and DR potential.

Role of Demand Response in Virginia's Resource Portfolio

The DR capabilities deployed by Virginia utilities can become part of a long-term resource strategy that also includes resources such as traditional generation resources, power purchase agreements, options for fuel and capacity, and energy efficiency and load management programs. Objectives include meeting future loads at lower cost, diversifying the portfolio to reduce operational and regulatory risk, and allowing Virginia customers to better manage their electricity costs.

The 2005 Energy Policy Act provisions for Demand Response and Smart Metering has led to a number of states and utilities piloting and implementing a Smart Grid, sometimes referred to as Advanced Metering Infrastructure (AMI). Smart Grid is a transformed electricity transmission and distribution network or "grid" that uses robust two-way communications, advanced sensors, and distributed computers to improve the efficiency, reliability, and safety of power delivery and use. For energy delivery, the Smart Grid has the ability to sense when a part of its system is overloaded and reroute power to reduce that overload and prevent a potential outage situation.

Principal benefits of Smart Grid technologies for DR include increased participation rates and lower costs. In 2009, Dominion plans to deploy 200,000 smart meters as part of a large demonstration program of smart grid technology in urban and rural areas of Dominion's service territory. Dominion expects to improve customer service and business operations through advanced system control, real-time outage notification, and power quality monitoring. As part of this program, Dominion deployed a number of smart thermostats for a residential critical peak pricing pilot during the summer of 2008. Dominion will measure customer responsiveness to changing energy prices and the impact on energy demand during peak usage periods.

Assessment of Demand Response Potential in Virginia

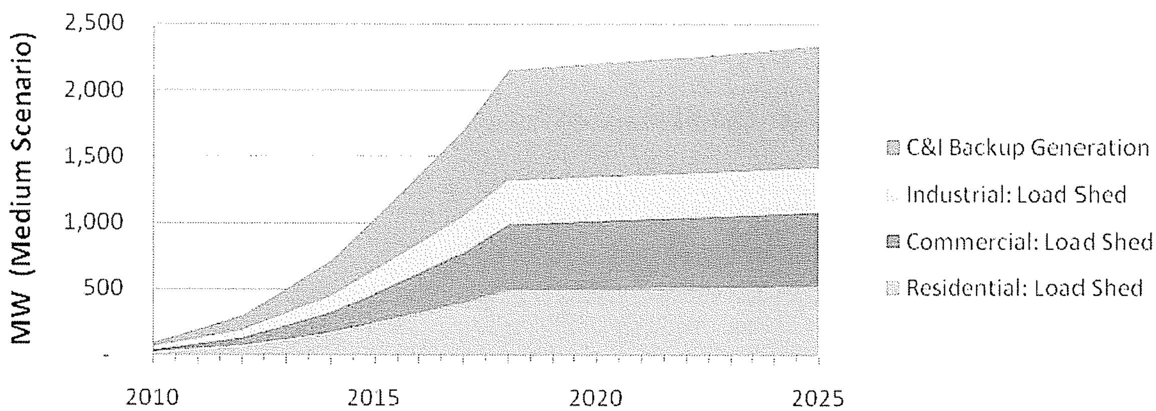
This assessment indicates that system peak demand can be reduced by approximately 7.2% or 2,209 MW in 2020 with the medium scenario. A more aggressive high scenario would result in a 10.8% or a 3,322 MW reduction in peak demand. These assessments assume that initial DR program designs are developed in 2009 with implementation starting in early 2010. This provides for a ten-year rollout of the DR efforts. It is expected that the first two years of implementation after the initial DR program designs will be used to fine-tune the programs.

Table 17 shows the resulting load shed reduction assessment for Virginia, by sector, for years 2015, 2020, and 2025, and Figure 16 shows the resulting load shed reductions possible for Virginia, by sector, from year 2010, when load reductions are expected to begin, through year 2025. These estimates reflect a sustained level of effort, and utilities are recommended to set targets for the high scenarios. These estimates include assumptions regarding energy and peak demand growth rates, participation rates, and program design, among others. These assumptions take into account the increased energy efficiency activities that will be occurring during this same period. The data inputs and assumptions are discussed in Appendix D. The overall trend in the DR program potential impacts in Table 17 and Figure 16 indicates that DR MWs grow rapidly through the end of 2018 as these years represent major implementation efforts. After 2018, the growth in DR MWs roughly follows the forecasted growth in peak demand.

Table 17. Summary of Potential DR in Virginia, By Sector, for Years 2015, 2020, and 2025 [a]

	Low Scenario			Medium Scenario			High Scenario		
	2015	2020	2025	2015	2020	2025	2015	2020	2025
Residential: Load Shed (MW)	143	299	310	238	499	516	333	699	723
Commercial: Load Shed (MW)	88	194	213	235	517	567	441	970	1,063
Industrial: Load Shed (MW)	72	145	147	162	327	331	289	582	588
C&I Backup Generation (MW)	302	639	698	402	865	930	503	1,082	1,163
Total DR Potential (MW)	605	1,288	1,367	1,038	2,209	2,345	1,566	3,332	3,537
DR Potential as % of Total Peak Demand (30,065 MW)	2.1%	4.2%	4.2%	3.6%	7.2%	7.2%	5.4%	10.8%	10.8%
[a] See Appendix D for underlying data and assumptions.									

Figure 16. Potential DR Load Reduction in Virginia by Sector (MW)



Recommendations

Key recommendations for fostering the growth of DR in Virginia are summarized below, with greater discussion contained in Appendix D. These recommendations are not listed in order of importance but they include:

1. Appropriate financial incentives for Virginia utilities either for programs administered directly by the utilities or for outsourcing DR efforts to aggregators.
2. Integrate DR programs with the delivery of EE programs.
3. Implement load reduction programs in he early years used as a shakeout period for program design and adapt the programs to achieve the projected impacts. This assessment is based on established technologies and program designs.
4. Implement programs focused on achieving firm capacity reductions. The following programs, which can be designed within a 12-month period, include:
    a. Residential and small business AC direct load control using switches or thermostats (or giving customers their choice of technology).[11]
    b. Auto-DR programs providing direct load curtailment for larger commercial and industrial customers.

[11] This approach is currently being used successfully by LGE Energy.

   c. Callable interruptible programs with manual response to an event notification for larger commercial and industrial customers where auto-DR approaches are not acceptable to the customer or technically not feasible.
   d. Aggressive enrollment of backup generators in DR programs.
5. Pricing should form the cornerstone of an efficient electric market. Daily time-of-use pricing and day-ahead hourly pricing will increase overall market efficiency by causing shifts in energy use from on-peak to off-peak hours every day of the year. Another example is "critical peak pricing," where utilities or system operators utilize an automated system to cut back electricity consumption amongst their customers in response to periods of unusually high demand.
6. Customer education should be included in DR efforts (as also recommended by the SCC Sub-group 3 (SCC 2007). There is a perceived lack of customer awareness of programs and incentives. In addition, new programs will need marketing efforts as well as technical assistance to help customers identify where load reductions can be obtained and the technologies/actions needed to achieve these load reductions. Also, high-level education on the volatility of electricity markets helps customers understand why utilities and other entities are promoting DR and the customers' role in increasing demand response to help match up with supply-side resources to achieve lower cost resource solutions when markets become tight
7. Increase clarity and coordination between the Federal and State agencies and programs (as also recommended by the SCC Sub-group 3 (SCC 2007). While states have primary jurisdiction over retail demand response, the FERC has jurisdiction over demand response in wholesale markets. Greater clarity and coordination between the Federal and State programs is needed.

MACROECONOMIC IMPACTS: IMPACT OF POLICIES ON VIRGINIA'S ECONOMY, EMPLOYMENT, AND ENERGY PRICES

In this section, we present the results of an assessment of the macroeconomic impacts of the medium case energy efficiency policy scenario recommendations on the economy of Virginia.[12] These policies result in a substantial reduction in consumer energy bill spending, while creating a significant number of new jobs. In fact, continued investments in energy efficiency resources would continue to yield energy resource benefits for many years into the future beyond our analysis period. The state therefore has the opportunity to transition its energy markets to a more sustainable system of production and consumption to benefit consumers and the environment.

Methodology

This economic evaluation is undertaken in three steps. First, we calibrate ACEEE's economic assessment model called DEEPER (Dynamic Energy Efficiency Policy Evaluation Routine) to reflect the economic profile of the Virginia economy (Laitner and McKinney 2008b), incorporating the anticipated investment patterns that are assumed in the reference case (e.g., construction of new electric power plants projected in the forecast). Second, we transform the set of key efficiency scenario results from the policy analysis above into inputs for the economic model. The resulting inputs include such parameters as:

1. The level of annual program spending that drives the policy scenario;
2. The electricity savings that result from the various energy efficiency policies or the level of alternative electricity generation from onsite renewable and combined heat and power technologies; and
3. The capital and operating costs associated with those technology investments.

[12] We do not present macroeconomic impacts for the low and high policy scenarios, though readers can approximate impacts based on magnitude of energy savings in each of those scenarios compared to the medium scenario.

Finally, the model is run to check both the logic and the internal consistency of the modeling results. A detailed description of the economic model is presented in Appendix F.

Impacts of Recommended Energy Efficiency Policies

For each year in the analysis period, the change in a sector's spending pattern relative to the reference scenario was matched to the appropriate sectoral impact coefficient. These negative and positive changes were summed to generate the estimated net result shown in the series of tables that follow. Presented here are three sets of impacts for the benchmark years of 2015 and 2025, which were estimated using the investment and savings results from the policy scenario.

Table 18 presents the estimated change in Virginia's electricity production patterns from the efficiency scenario compared to the reference case, along with the investment and program costs required to achieve these savings. These patterns are driven by the energy efficiency policy initiatives outlined in the policy analysis presented above (a detailed table with data for the years 2010, 2015, 2020, and 2025 can be found in Appendix F).

Table 18 also presents the changes in consumer expenditures that result from these policies. While the first row in the table presents the full cost of the energy efficiency policies, programs, and investments, the utility customers will likely borrow a portion of the money to pay for these investments. Thus, "annual consumer outlays," estimated at about $700 million in 2015 and rising to $950 million in 2025, include actual "out-of-pocket" spending for programs and investments, along with money borrowed to underwrite the larger technology investments. The annual electricity bill savings reported in the table are a function of reduced electricity purchases from the Virginia utilities at the initial electricity prices in a given year.

Table 18. Changes in Virginia Electricity Production and the Financial Impacts from the Medium Energy Efficiency Policy Scenario: 2015 & 2025*

(Millions of 2006 $)	2015	2025
Annual Total Cost**	$575	$668
Savings Relative to Reference Case:		
Cumulative Savings (GWh)	9,957	27,914
Cumulative Savings (%)	7.9%	19.4%
(Millions of 2006 $)		
Annual Consumer Outlays	$698	$947
Annual Electricity Savings***	$866	$2,448
Annual Price of Electricity Savings***	$312	$681
Annual Net Consumer Savings	$480	$2,182
Cumulative Net Energy Savings	$1,091	$15,189

* 'Annual' refers to the given benchmark year. 'Cumulative' is the sum total from previous years beginning with 2008.
**Annual Total Costs include administrative costs to run programs, incentives provided to consumers, and investments in energy efficiency devices (investments are from both utilities and consumers).
***Annual Electricity Savings is the amount of electricity that consumers save and its associated value in lowered energy bills. Annual Price of Electricity Savings is additional savings due to reductions in the *price* of electricity. Since consumers are using less electricity, demand falls, so then price.

Energy efficiency policies provide resources that enable consumers to make investments that change the patterns of electricity consumption and production. Total costs include program spending, incentives, and investments of $575 million in 2015, which when combined with consumer borrowing totals about $700 million. The cumulative impacts on electricity production are quite large in 2015, reducing electricity demand by about 10,000 GWh (8% below reference case demand). In 2015, the reduced electricity consumption saves consumer nearly $900 million gross in electricity costs. Total costs rise to $670 billion dollars in 2025, or about $950 million including consumer borrowing. The cumulative impact of activities over the time horizon steadily reduces the demand for conventional electricity generation so that by 2025 energy efficiency displaces the forecasted electricity production by about 19%. These investments result in consumer savings of $2.4 billion gross in lowered electricity costs.

Our analysis also explores the impact of reduced consumption on electricity prices. Previous research has shown that in tight markets, small changes in energy demand can have large impacts on energy prices, particularly for natural gas (see Elliott and Shipley 2005; Elliott 2006). The changed electricity production patterns, including both reduced electricity demands and efficiency technology investments, produces a negative adjustment in the electricity supply costs due to the lower capital and operating expenditures associated with the energy efficiency policy scenario. Essentially, the efficiency policies reduce wholesale electricity prices. Our estimates of these effects are shown in Table 18 as "Annual Price of Electricity Savings." As shown, we estimate that consumers can save an additional $300 to $700 million gross annually, relative to the reference case, due to these price effects.

The category of annual net consumer savings estimates the consumers' total savings from both lower electricity consumption and lower prices, minus consumer outlays. In 2015, electric customers save about $900 million in reduced electricity consumption and $300 million in reduced electricity prices, and spend $700 million in outlays for a net consumer gain of about $500 million. In 2025, net annual consumer savings grows nearly five-fold from the 2015 value to $2.2 billion. The last row in the table shows cumulative net consumer savings, which sums the annual net savings over the study time period. In 2015, net cumulative savings are $1 billion and grow to $15 billion by 2025.

Once each of the net sector spending changes has been evaluated for a given year, the DEEPER model then evaluates impact on jobs and wages sector-by-sector, and evaluates their contribution to the state's GSP. Table 19 highlights the net impacts, again for the benchmark years 2015 and 2025.

Table 19. Economic Impact of Energy Efficiency Investment in Virginia

Macroeconomic Impacts	2015	2025
Jobs (Actual)	675	9,820
Wages (Million $2006)	63	583
GSP (Million $2006)	202	882

The analysis estimates a net contribution to the Virginia employment base as measured by full-time jobs equivalent of 675 in 2015 and 9,820 in 2025 (see Table 19 and Figure 17. In Virginia, the electric services sector utilizes 2.68 jobs for every $1 million investment. But, sectors vital to energy efficiency improvements, like construction, utilize 7.8 jobs per $1 million invested. Once job gains and losses are netted out in each year, the analysis provides the net annual employment benefit of the policies that impacts the larger Virginia economy. Figure 17 provides year-by-year impacts on net jobs in Virginia. The increase in jobs and the changes in job mix result in a net gain to the state's wage and salary compensation, measured in millions of 2006 dollars, as shown in Table 19 and Figure 18.

Figure 17. Net Job Impacts for Virginia (2008-2025)

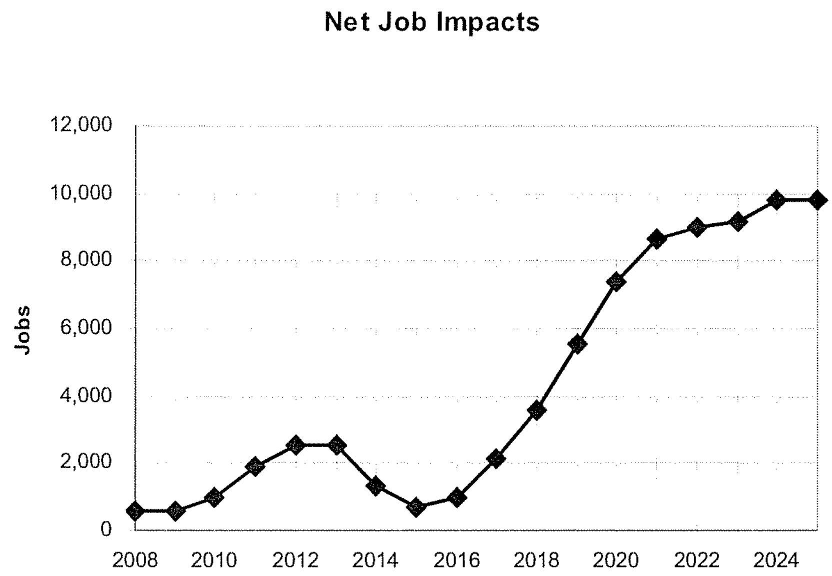
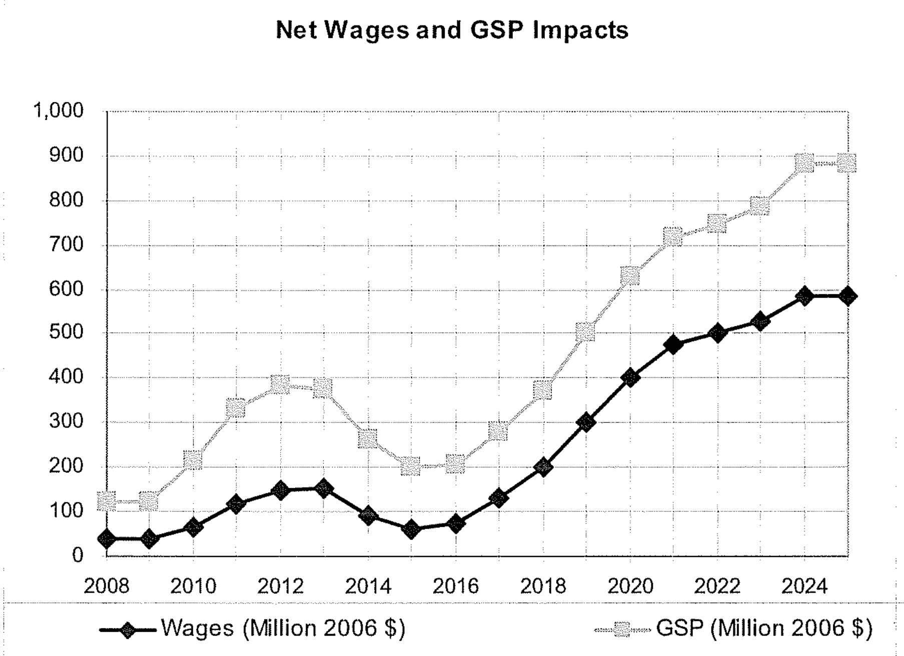


Figure 18. Wages and Gross State Product Impacts for Virginia (2008-2025)



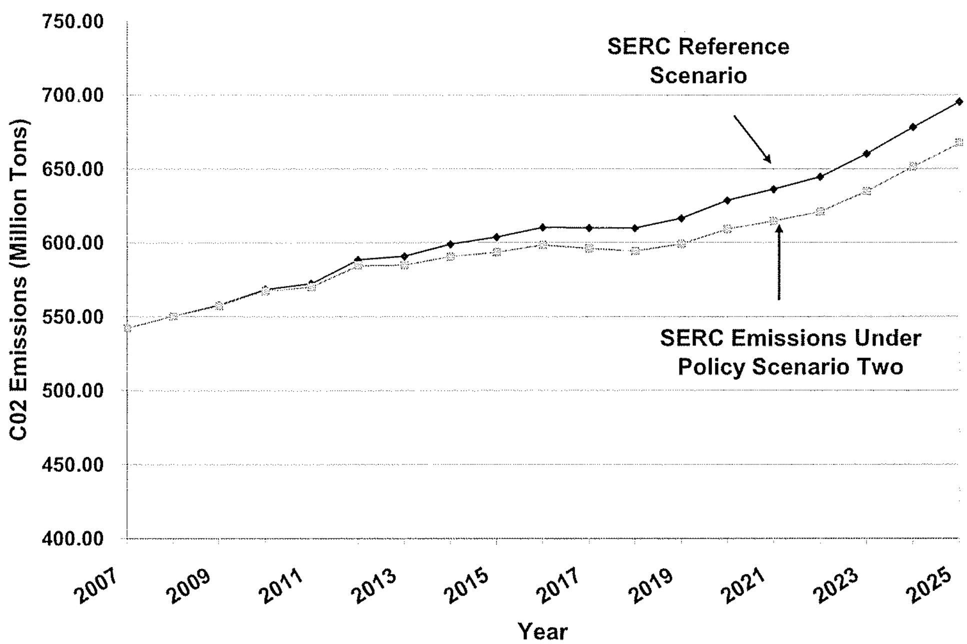
Early program stimulus and investments drive an increased economic impact, creating an average of 1,500 jobs each year in the first six years of the study. These investments increase wages and GSP throughout Virginia (see Figure 18). Better, more efficient use of the energy supply reduces the need for imported energy, and keeps those revenues from leaking outside the state. The years 2014 through 2016 provide smaller increases in jobs, wages, and GSP. The reference case for this analysis included large investments in temporary power plant construction during this period without energy efficiency investments. During the period 2013-2018, the reference case's investments are higher relative to other years in the reference case, and by comparison make the policy case's investments appear to generate lower levels of economic returns.

EMISSIONS IMPACTS IN POLICY SCENARIO

Meeting the demand for electricity through efficiency resources reduces electricity generation and thus any environmental impacts that would result can be avoided. Efficiency represents a cost-effective strategy to reduce global warming emissions. One caveat of the avoided emissions from efficiency that readers should note is that Virginia imports a significant share (about 30%) of its electricity from outside the state and therefore the avoided electricity is not directly attributable to specific power plants in Virginia but rather from the wholesale power market.

Policies from the medium energy efficiency scenario would reduce carbon dioxide (CO_2) emissions in the Southeast by 10 million tons in 2015 and 28 million tons in 2025, or 1.7% and 4% of total emissions in the region, respectively (see Figure 19). Through 2025, energy efficiency can reduce CO_2 emissions cumulatively by about 240 million tons. In 2006, Virginia accounted for just over 46 million tons of CO_2 emissions, almost 9% of regional emissions (EIA 2007a). Electricity savings from efficiency policies in Virginia would have an impact across the entire Southeast. We therefore estimate these CO_2 reductions from energy efficiency programs and policies relative to the entire region (see Appendix B.2 for discussion on the methodology).

Figure 19. SERC CO_2 Emissions in Reference Scenario and Policy Scenario Two

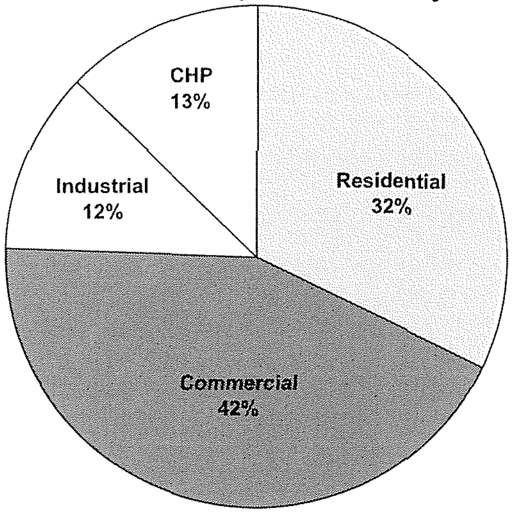


SUMMARY OF FINDINGS

Energy Efficiency Resource Potential

ACEEE's assessment of cost-effective energy efficiency potential in Virginia estimates efficiency resources equivalent to about 30% of the electricity needs of the Commonwealth in 2025. Energy efficiency resources are identified across all sectors: residential, commercial, and industrial (see Figure 20), which highlights the critical point that all players in Virginia can make contributions to improve energy efficiency in the Commonwealth. Combined heat and power and demand response further contribute to the potential for both lower electricity consumption and reduced peak demand.

Figure 20. Summary of Energy Efficiency Resource Potential (44,000 GWh or 31% of Projected Electricity Use in 2025)



Impacts of Energy Efficiency and Demand Response

ACEEE recommends a suite of energy efficiency and demand response policies that would enable Virginia to tap into its energy efficiency potential. These recommendations include:

- Energy savings target (EERS)
- Demand response initiatives
- Lead by example in state and local government facilities
- Manufacturing initiative
- CHP supporting policies

Impacts on electricity use in Virginia over the study time period are shown in Figure 21. The combined effects of energy and demand response on overall summer peak demand are shown in Figure 22 and Table 20.

Figure 21. Estimated Reductions in Electricity Use in Virginia through Energy Efficiency — *Medium Scenario*

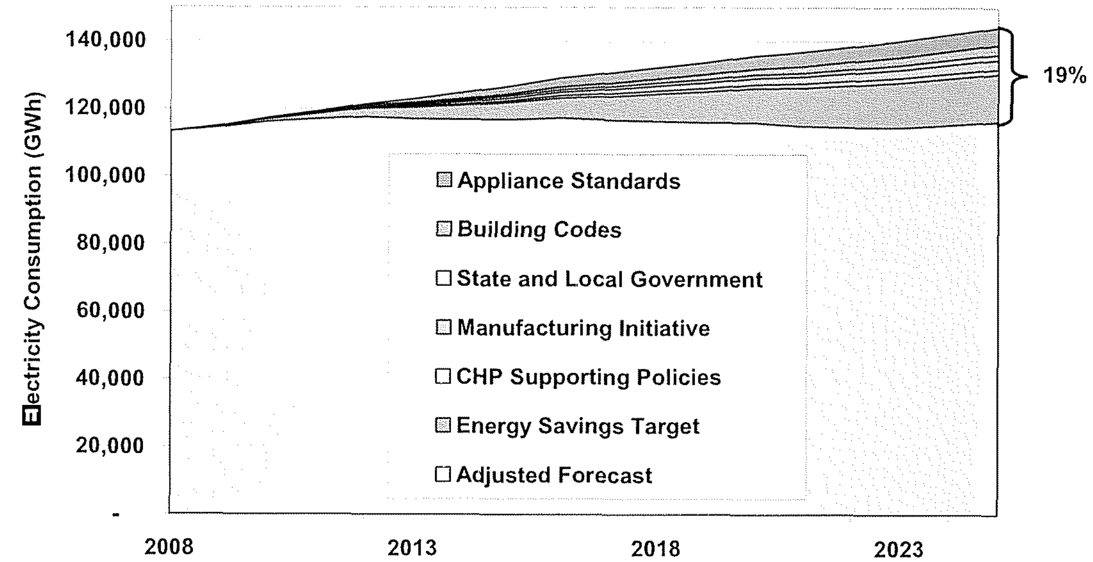
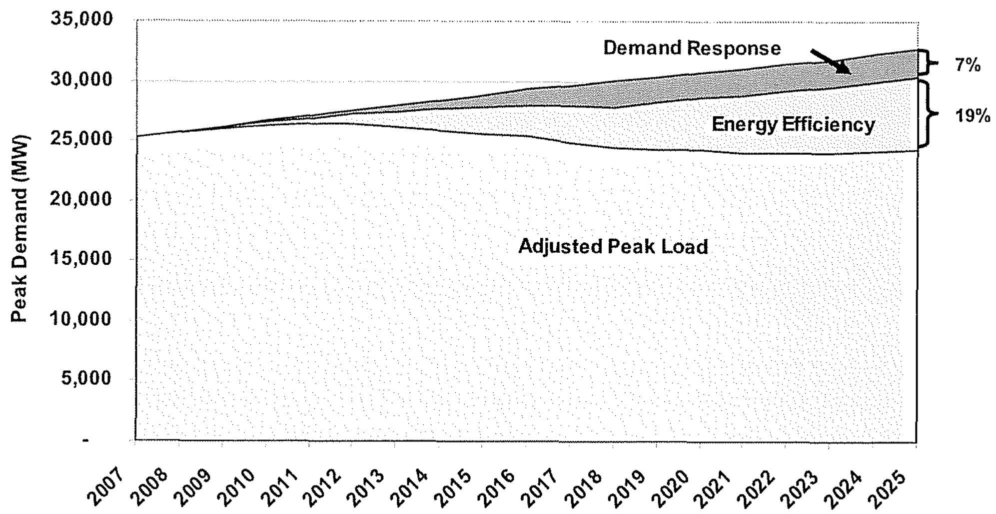


Table 20. Summary of Peak Demand Reduction Potential in Virginia

	2015	2025	% Reduction
Energy Efficiency Peak Reductions	2,169	6,048	18.5%
Demand Response Peak Reductions	1,038	2,345	7.2%
Total Peak Reductions	3,206	8,392	26%
% Reduction (total relative to forecast)	13%	26%	

Figure 22. Estimated Reductions in Summer Peak Demand through Energy Efficiency and Demand Response — Medium Scenario (2025 peak reduction = 8,400 MW, or 26%)



Consumer Savings

The energy savings from these efficiency policies can cut the electricity bills of customers by a net $500 million in 2015. Net annual savings grow nearly five-fold to $2.2 billion in 2025. While these savings will require some public and customer investment, by 2025 net cumulative savings on electricity bills will reach $15 billion. To put this into context, an average household will save a net $5 on its monthly electricity bill by 2015 and $20 per month by 2025. These savings are the result of two effects. First, participants in energy efficiency programs will install energy efficiency measures, such as more efficient appliances or heating equipment, therefore lowering their electricity consumption and electric bills. In addition, because of the current volatility in energy prices, efficiency strategies have the added benefit of improving the balance of demand and supply in energy markets, thereby helping to stabilize and contain increases in regional electricity prices for the future.

Macroeconomic Impacts

Investments in efficiency have the additional benefit of creating new, high-quality "green-collar" jobs in the Commonwealth and increasing both wages and GSP. Our analysis shows that energy efficiency investments can create nearly 10,000 new jobs in Virginia by 2025 (see Table 21), including well-paying trade and professional jobs needed to design and install energy efficiency measures. These new jobs, including both direct and indirect employment effects, would be equivalent to almost 100 new manufacturing plants relocating to Virginia, but without the public costs for infrastructure or the environmental impacts of new facilities.

Table 21. Economic Impact of Energy Efficiency Investments in Virginia

Macroeconomic Impacts	2015	2025
Jobs (Actual)	675	9,820
Wages (Million $2006)	63	583
GSP (Million $2006)	202	882

DISCUSSION AND RECOMMENDATIONS

The objectives of this ACEEE project and study are threefold:

- to engage varied stakeholders in Virginia who have a vested interest in energy issues on what is politically possible;
- to perform an analysis of the potential for increased energy efficiency in Virginia and to make and analyze specific policy recommendations tailored to the Commonwealth; and
- to inform the dialogue of Virginia stakeholders as energy efficiency policies and programs are considered utilizing the study's findings and to provide ongoing follow-up (as resources allow) to interested parties.

Findings from the Stakeholder Process

The first aspect of this project—engaging stakeholders—reached out to as many different interested parties in Virginia as time and resources allowed. This outreach included state government, electric utilities, the utility commission, industrial and manufacturing consumers, and environmental organizations. In addition, a more limited communication was established with low income advocates and representatives from the state legislature though with less success than hoped due to lack of availability of representatives, since the legislature was not in session for the most part for the duration of this study. A key part of this effort was the sharing of a draft of this report with over fifty different stakeholder groups and individuals.

Several key issues of concern emerged from the comments received on a draft of the report. Common threads in these comments included:

- Cost-effectiveness of energy efficiency measures and avoided costs
- Data availability issues
- Reference case assumptions

Little consensus was found among the responders. In fact, the various comments reflected the highly polarized nature of the energy debate in the state. It was clear throughout the stakeholder process that there was unlikely to be much consensus on next steps for the state. It will take more dialog and additional analysis to make decisions and take action but at this point it is expected that this report will at least give some starting place for further deliberations, which was one goal of the study.

Cost Effectiveness and Avoided Costs

ACEEE's assessment of the overall potential for energy efficiency in Virginia took the perspective of an electric customer—i.e., if a consumer investment in efficiency costs less per kWh of electricity *saved* than a customer would have paid for that kWh *delivered,* then that investment is cost-effective. This approach is not what the utilities stakeholders use and, therefore, admittedly produces a different result from their current utility cost-effectiveness tests. There is no single definition of cost-effectiveness in the industry to evaluate the benefits of energy efficiency, and electric utilities use several different tests to calculate the costs and benefits of efficiency programs.[13] One commonly used method is the Total Resource Cost (TRC) test, which evaluates the net benefits of energy efficiency to the region as a whole. This test evaluates benefits as the avoided costs to utilities of not *generating* electricity. The Participant Cost Test, on the other hand, evaluates benefits as the costs that program participants avoid by not *purchasing* the saved electricity. Although our assessment of the efficiency resource potential takes the customer perspective, ACEEE used both the TRC and Participant tests in its assessment of the specific suite of energy efficiency policies, and both tests show positive, net benefits.

We also found a significant disagreement about what the future cost of electric resources would be in the state. While we developed approximate annual average utility avoided costs for this report, we strongly encourage that a more detailed assessment of avoided costs be undertaken as part of the Commonwealth's energy planning process. The development of a single, consensus avoided cost estimate would provide a common basis upon which evaluation of the best resource mix for the state could be based. Therefore, this issue might be an appropriate subject for an SCC proceeding.

Data Availability Issues and Reference Case

Difference in opinion about data and forecasts are in part due to the lack of consistent energy data and forecasts for the Commonwealth—as it is for most states. This lack of reliable data is one of the biggest challenges ACEEE faced in undertaking this and previous state studies. This problem results from a combination of factors. The movement in the 1990s toward utility restructuring in many states including Virginia not only resulted in the suspension of most energy efficiency utility programs, but also led to termination of many energy data collection and market surveying activities. This problem is not unique to states either. Budget cuts over the past decade have resulted in the termination of important data sources by federal agencies such as DOE's Energy Information Administration and the U.S. Census Bureau.

The absence of an entity to rationalize different data and forecasts creates uncertainty that distracts from the clear need to focus on the bigger energy policy issues facing Virginia—issues this report can hopefully inform in terms of future deliberations for those making critical policy decisions. Due to the absence of a consistent electricity forecast for Virginia, we derive a forecast of electricity consumption growth based on PJM's 2008 annual load forecast, using only its service territories in Virginia to derive weighted-average growth rates for Virginia. We then apply this overall forecast to actual 2007-

[13] See The Regulatory Assistance Project (www.raponline.org) for more information.

year electric sales data for Virginia (EIA 2007c). Using this methodology, and extending the forecast through 2025 to cover the study period of this analysis, total electricity consumption in the state is projected to grow in the reference case at an average annual rate of 1.4% between 2008 and 2025.

If Virginia is serious about realizing the benefits of energy efficiency resources, the state, regional market entities including PJM, and utilities must be focused and strategic about identifying data needs and following through on collection of these data resources. These groups should work collaboratively to develop and implement a coordinated plan for collecting this information in order to effectively design and evaluate the performance of efficiency programs now and in the future.

To accomplish this task, a state agency such as DMME or SCC, or some third party such as a university[14] or a consortium of utilities and other key interested parties should be designated as the energy data coordinator for the state. While individual utilities will likely resume the collection of some of this data to support their programs, it is important that the collection is comprehensive and consistent across the state. This data collection entity should consider developing data resources including the following:

- *A consensus statewide electricity and peak demand reference forecast* on which to base the current and future efficiency targets.
- *Appliance saturation surveys* (similar coordinated surveys conducted by each utility, or perhaps a single survey with each utility on the steering committee and the study designed to provide utility-specific breakdowns).
- *New construction baseline surveys* (e.g., a statewide survey with utility-specific information). These should include building size and key features suggestive of energy efficiency.
- *End-use load-shape studies* to help identify the contribution of each major sectoral end-use to peak electrical demand. Power costs are particularly high during peak demand periods, and understanding and reducing the major loads at times of peak demand can be very cost-effective.
- *Measurement and verification studies* using common methodologies and reporting formats to provide data on measure and program costs and savings.

By having a single entity with the responsibility and resources to collect and analyze energy data, the state will be able to verify that its policies are achieving their goals, and future analysts will have the necessary data to identify energy efficiency opportunities and design programs to realize these energy efficiency resources. While having good data and forecasts will not save energy by itself, it represents an important enabling infrastructure, and can remove a distraction that appears to be inhibiting efforts to advance the energy policy discussion.

Workforce

Virginia, like most if not all states, faces growing concerns about its energy workforce due in part to the aging of the incumbent energy workforce complicated by a lack of entry of younger workers over the past two decades. This workforce shortage impacts energy efficiency particularly, since as noted in the economic analysis, energy efficiency tends to be more labor intensive than are supply resources, requiring a trained workforce to identify and implement the efficiency resources whether they are industrial plant process optimization or residential HVAC tune-ups. The workforce issue represents a key infrastructure challenge that is becoming more widely recognized (NAPEE 2007), so the Commonwealth must address the need to build an adequate workforce to meet the demands of the market. This issue is moving to the forefront in many states seeking to expand energy efficiency, and requires a focused response by state leaders, particularly with universities and community colleges. Leading states like Texas, New York, and California are mobilizing their workforce training infrastructure to begin to develop the energy efficiency experts and technicians needed to meet future market demand. Fortunately, Maryland already has expertise on energy efficiency within the University of Maryland system, which needs to be nurtured and expanded across the state. Virginia

[14] For example. California has CALifornia Measurement Advisory Council (CALMAC). See www.calmac.org.

has already taken some initial steps in this regard as is discussed in our manufacturing initiative proposal. The state should consider forming an energy workforce coordinating council that can bring together the key players across the state so they can begin to prepare to meet the staffing needs that a clean energy future requires.

Recommended Next Steps

ACEEE offers this report to the Commonwealth to help inform its deliberations on energy and climate change policies. We have attempted to tailor our nationwide experiences to the specific needs and opportunities of the state, recognizing that what is implemented with respect to programs and policies should be a decision of the citizens through their elected officials.

In preparing this report, ACEEE has drawn upon its almost three decades of work on energy efficiency policies and programs. Our policy recommendations are based upon our assessment of "best practices." We intend this report as a roadmap for further development of energy efficiency policies. We have attempted in many places to identify resources that are available for further development, and stand prepared to assist the Commonwealth with additional information and referrals. Policymakers in the state need to decide what policies and program options they are committed to pursuing.

Role of Key Policymakers

In our recommendations, we have suggested who ACEEE sees as the best positioned to lead the implementation of our program and policy recommendations. In ACEEE prior research, we have documented that many of these policies and programs can be successfully implemented by a number of different entities, and the choice is up to the policymakers.

- ***The Governor***—The Governor plays a key role in this process. Governor Kaine has already assumed the role of leader in the deliberations of energy efficiency and climate change policy for the state. In fact his leadership was an important motivation to ACEEE in undertaking this study. The Governor has the potential to implement at least parts of a number of our suggestions, including the expansion of the state and local facilities initiative, the manufacturing initiative and the proposals for expanded public awareness and education. In part, the Governor's most important role may be to use his position to raise awareness among the policy community and the public as to the role of energy efficiency in utility and climate policy.
- ***Legislature***—The legislature has already played a key role in setting the Commonwealth on its current energy path, and will continue to play a pivotal role because of its ability to both fund and direct energy policy for the state. The legislature should consider such steps as adoption of state appliance and equipment efficiency standards; increasing the Commonwealth's energy savings target; and funding the state and local government, manufacturing and low-income initiatives through the budget process.
- ***State Corporation Commission***—The SCC has been among the key agencies involved with the implementation of utility energy efficiency programs. The commission plays the role of the representative of consumers across the state, insuring that they receive the energy benefits that could reduce their future energy costs while enhancing the economic stability of the state. The SCC should oversee implementation of programs to reach the current 10% savings target, and address the lack of data needed to help these programs succeed.
- ***State Agencies***—Various agencies would play roles implementing various provisions such as the expanded state and local facilities initiative. The agencies could also play important supporting roles in the education and outreach effort that would be critical in engaging the state's consumers with the information needed for them to make informed energy investment decisions.
- ***Local Governments***—Local government entities are uniquely positioned to implement several important suggestions including implementation of building codes and programs for local government facilities (as is discussed in Elliott and Eldridge 2007).

- ***State Educational System***—With workforce identified as a key need, the state educational system would play a critical role in ensuring that a trained workforce is developed to fill the jobs that an expanded investment in energy efficiency would create.

Program and Policy Implementation

For most of the policy and programs, ACEEE has made suggestions as to what entity should implement the policies and programs. In ACEEE's review of successful programs and policies, a number of different entities have successfully implemented the programs and polices in other states (York, Kushler and Witt 2008). Our suggestions for Virginia are based on our assessment of what programs and policies are currently being implemented by existing entities, and the ability to leverage these ongoing efforts. For example, the state DMME, VPMEP, and universities are already delivering services for the manufacturing community, so building on those existing efforts allows expanded services to be delivered sooner. Similarly, the utilities have current relationships with their commercial and residential customers, so adding energy efficiency programs to the existing delivery channel appears the quickest way to ramp up efficiency programs to these markets. The state could implement an independent energy efficiency program administrator model, such as Vermont has done with Efficiency Vermont.[15] However, the establishment of such an entity would require significant time to organize the entity and staff up to deliver the programs.

CONCLUSIONS

The Commonwealth of Virginia finds itself at a juncture in the road with respect to its energy future. The state can either continue to depend upon conventional energy resource technologies to meet its growing needs for electric power as it has for more than a century, or it can chose to slow—or even to reduce—future demand for electricity by investing in energy efficiency and demand response. As this assessment documents, there are plenty of cost-effective energy efficiency and demand response opportunities in the state. However, as this report also discusses, these opportunities will not be realized without changes in policies and programs in the state. The state ranked 38th out of the 50 states in ACEEE's 2007 state energy efficiency scorecard in large part because there has been little attention to energy efficiency in the past (Eldridge et al. 2007). We suggest a wide array of energy efficiency and demand response policies and program that have proven successful in other states, and can meet 90% of the increase in the state's electricity needs over the next 18 years, and meet 20% of the increase in peak demand. These policies and programs are already proving themselves in other states, delivering efficiency resources and reducing consumer electric expenditures. **And**, these policy and programs can accomplish this at a lower cost than building new generation and transmission, while at the same time creating close to 10,000 new, high-quality "green collar" jobs in 2025.

These policy and programs suggestions should not be viewed as prescriptive, but as the starting point for a dialog among stakeholders on how to realize the efficiency resource that is available in the state on the demand side. ACEEE's suggestions are based on our review of existing opportunities and stakeholder discussions, and reflect proposals that we think are politically plausible in the state. Clearly there are other policies and programs, some of which we suggest in our aggressive scenario, that could be implemented to realize even more of the available energy efficiency resource.

Nor do we suggest that these recommendations will meet all of the state's future energy needs. While energy efficiency is perhaps the only new energy resource available in the immediate future and can make an important contribution in the longer term, the state will need additional resources to meet the remainder of the new load and replace older, dirtier power plants in the coming years. Energy efficiency can, however, buy time for a robust discussion about what other resource choices—both conventional and alternative—the state will make in the future.

[15] For more information, visit www.efficiencyvermont.com/pages/.

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Appendix Table of Contents

Appendix A - Reference Case

A.1. Projection of Electricity Consumption and Peak Demand

The first task in developing an energy efficiency and demand response potential assessment is to determine a reference case forecast of energy consumption, peak demand, and electricity prices in the state in a "business as usual" scenario. When developing a reference case, it is preferable to use forecasts that are specific to the state or region and that are agreed upon by key stakeholders. Initially we used the State Corporation Commission's (SCC) forecast from 2005, however the forecast only projected through 2011 and only included data from Dominion Power, referred to in the forecast as Virginia Power and Electric Company (SCC 2005). Furthermore, the projections we estimated using the growth rate from SCC's forecast were not consistent with projections we derived from other sources. Therefore, it was in our interest to opt for the methodology below. We report the reference case assumptions over the 2008-2015 study period.

A.1.1. Electricity Forecast

Virginia is part of PJM, the regional transmission operator for the Mid-Atlantic and parts of the East Central Area. PJM projects electricity demand on an annual basis. We used their 2008 forecast, which projects demand through 2023, to estimate an electricity forecast for Virginia. PJM does not estimate electricity demand for specific states, but does look at specific geographic zones. For the AEP, APCo, Dominion, and DP&L zones, the four regions that fall within the state of Virginia, PJM projects electricity demand to grow at an average annual rate of 0.92%, 0.59%, 1.60%, and 1.56%, respectively, between 2008 and 2023 (PJM 2007). We derived a forecast specific to Virginia by estimating the portion of electricity demand in each geographic region that falls within Virginia, and prorated regional sales data by Virginia electricity sales data by utility (EIA 2006c).

We forecasted growth in electricity consumption by taking PJM's 2008 annual load forecast through 2022 and adjusting it specifically to those service territories in Virginia to derive a weighted-average growth rate for Virginia. We then applied this overall forecast to actual 2007-year electric sales data for Virginia from the March 2008 edition of the *Electric Power Monthly* (EIA 2008a) and we adjusted to sector-specific rates using *Annual Energy Outlook* sector growth rates for the South Atlantic (EIA 2007c). Using this methodology, and extending the forecast through 2025 to cover the study period of this analysis, total electricity consumption in the state is projected to grow in the reference case at an average annual rate of 1.4% between 2008 (the analysis base year) and 2025, and 1.2%, 2.0%, and 0.2% in the residential, commercial, and industrial sectors respectively. Actual electricity consumption in 2007 was 110,924 GWh (EIA 2007c), and in the reference case grows to 126,833 GWh by 2015 and 144,195 GWh by 2025.

A.1.2. Peak Demand Forecast

According to data from PJM's 2008 forecast, peak demand in the AEP, APCo, Dominion, and DP&L zones is projected to grow 1.0%, 0.8%, 1.6%, and 1.9% respectively. To ascertain Virginia-specific load growth for each utility we again estimated the portion of peak demand in each of the geographic regions that falls within Virginia and prorated regional sales data using Virginia electricity sales data by utility.

We derived an overall peak demand (MW) forecast for Virginia from the electricity forecast described above and assumed a 55% load factor, based on PJM load data for Dominion in 2007. Using this methodology, we estimated a 2008 peak demand of about 26,000 MW, rising to nearly 33,000 MW in 2025 and an average annual growth rate of 1.4%.

Table A-1 Retail Electricity Sales and Peak Demand Forecast

	2010	2015	2020	2025	Average Annual Growth Rate
Electricity (GWh)					
Residential	46,721	50,097	53,318	55,503	**1.27%**
Commercial	50,710	56,522	62,129	68,083	**2.09%**
Industrial	19,920	20,214	20,376	20,608	**1.08%**
Total	**117,351**	**126,833**	**135,823**	**144,195**	**1.60%**
Summer Peak Demand (MW)					
Total	**26,771**	**29,054**	**31,120**	**32,865**	**1.45%**

A.1.3. Population

Population estimates were needed for this analysis to determine per-capita sales data. We consulted Economy.com (2008) for data on population in the State of Virginia. According to this source, population in Virginia will grow at an average annual rate of about 0.8%.

Table A-2 Virginia Population Forecast

	2010	2015	2020	2025	Annual Growth Rate
Population Estimate	7,952,084	8,287,240	8,618,034	8,949,443	0.80%

A.1.4. Retail Electricity Prices

ACEEE also developed a possible scenario for retail electricity prices in the reference case. Readers should note the important caveat that ACEEE does not aim to predict what electricity prices in Virginia will be in either the short- or long-term. Rather, our goal is to suggest a possible scenario, and to use that scenario to estimate impacts from energy efficiency on electricity customers in Virginia.

Shown in Table A-3 are 2007 electricity prices in Virginia (EIA 2007c) and our estimates of retail rates by customer class over the study time period. This price scenario is based on three key factors. First, we use the average generation cost of electricity in Virginia over the time period from the analysis done by Synapse Energy Economics, discussed in the next section of the Appendix. These costs range from 6.3 to 7.2 cents per kWh over the study time period (in 2006$). Next, we use estimates of retail rate adders (the difference between generation costs and retail rates, which accounts for transmission and distribution costs) from the *Annual Energy Outlook* for the Southeastern Electric Reliability Council (SERC) (EIA 2007c). According to AEO, transmission and distribution cost adders for SERC range from about 2 to 2.1 cents per kWh. Finally, we estimate expected near-term increases due to fuel adjustments by investor-owned utilities and expectations of rate caps expiring in December 2008. By 2010, we assume that retail prices reach the production cost levels as estimated by Synapse plus the SERC-average retail price adders for transmission and distribution.

Table A-3. Retail Electricity Price Forecast Scenario in Reference Case (cents per kWh in 2006$)

	2007*	2010	2015	2020	2025	Average
Residential	8.5	10.1	10.0	10.1	10.5	10.0
Commercial	6.3	9.1	8.9	9.1	9.4	8.9
Industrial	4.9	6.8	6.8	6.9	7.2	6.8
Average	6.9	8.8	8.7	8.9	9.2	8.7

Note: These figures are in real, 2006-year dollars and therefore do not take into account inflation.
* Actual rates (EIA 2007c), converted to 2006$

A.2. Projection of supply prices and avoided costs

Synapse Energy Economics developed projections of supply prices and avoided costs used in this study. These estimated were developed based on key input assumptions that were developed as part of the stakeholder engagement process. Synapse then developed a simplified Electricity Planning and Costing Model to develop the projections. As noted in the main report, two sets of projections were developed for the reference and moderate policy cases.

A.2.1. Caveats

The projections of production costs and avoided costs presented in this memo are based upon a number of simplifying and conservative assumptions that the stakeholder group consider reasonable for the purpose of this high-level policy study. These simplifications include use of a single annual average avoided energy cost to evaluate the economics of energy efficiency measures rather than different avoided energy costs for energy efficiency measures with different load shapes. In addition, Synapse Energy Economics considers it unrealistic to rely upon projections that exclude the cost of compliance with anticipated CO_2 emission regulations.

A.2.2. Key Assumptions

This section describes the key inputs to the electricity model that Synapse Energy Economics has developed for this project (Synapse electricity cost model), the rationale for the proposed values and the sources of those values. The final inputs are based upon a set of draft inputs developed by Synapse[1] that ACEEE reviewed with key stakeholders in Virginia. The key substantive differences between these final input assumptions and the draft input assumptions are changes in the projected natural gas prices and carbon compliance costs. ACEEE decided to use a lower projection for natural gas prices and zero costs for carbon compliance. In addition, ACEEE provided a Reference Case load forecast. *The values of these inputs are provided in Attachment A to this memo.*

The memo also provides a description of the Electricity Cost Model that we use to estimate future production costs and avoided costs. That description is provided in Appendix B.

Changes from the August 15 version, Deliverable 1 b, are indicated in ***italics***.

A.2.3. Input Assumptions

The key inputs to the electricity model are presented under the following twelve categories:

- Basic Modeling assumptions
- *Base year Sales and revenues*
- Base year Load and resource Balance

[1] Deliverable 1 Input Assumptions for Electricity Cost Model, June 23, 2008.

- In-State Base Year Generation Resource Performance and Cost Data
- New Generation Resource Performance and Cost Data
- Fuel Types
- Annual Energy and Peak Load
- Capacity retirements
- Capacity additions
- Fuel prices
- Purchased Power Costs
- Carbon Emission Costs

Basic Modeling Assumptions:

- The base year is 2007. All monetary values are reported in constant 2006 year dollars unless noted otherwise.
- The study period begins in 2008 and ends in 2030, an analysis period of 23 years.
- The reporting period is 2009 through 2025, a total of 17 years.
- The financial parameters for costing resource additions are as follows:
- Inflation Rate. 2.50%. Rationale - the twenty year average (1987-2006) derived from the chained GDP deflator is 2.47%.
- Nominal Discount Rate. ***9.0%.*** This represents the value for a regulated utility such as Dominion with a mix of equity and bond financing. Based on a 50/50 equity/debt mix with ***11%*** for equity and 7% for debt. Used for levelization of capital expenditures. Actual rates for specific projects will vary depending on the nature of the project and the implementing entity.
- Real Discount Rate. 5.85%. Derived from the Nominal Discount Rate and the Inflation Rate.
- Income Tax Rate. Federal rate of 35% and VA state rate of 6%. ***Property tax rate of 0.5% per annum of the initial plant cost based on the posted property tax rates for VA counties and considering plant location in a rural area.***

A.2.4. Base Year Sales and Revenues

The historic sales and revenues data are obtained from the EIA's "State Electric Profile" Table 8 (http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html). This has been supplemented with data for 2007 from the EIA "Electric Power Monthly" report of March 2008 which contains data through December of 2007 (tables 5.4 and 5.5) (http://www.eia.doe.gov/cneaf/electricity/epm/epm_ex_bkis.html). The historic data indicates that about 35% of Virginia's energy needs and 22% of the capacity needs are met from outside of the state.

A.2.5. Base Year Load and Resource Balance

The historic sales and revenues data are obtained from the EIA's "State Electric Profile" Tables 5, 8 and 10 (http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html). This has been supplemented with data for 2007 from the EIA "Electric Power Monthly" report of March 2008 which contains data through December of 2007 (tables 1.6, 4.6, 4.20, 4.12 and 4.13) (http://www.eia.doe.gov/cneaf/electricity/epm/epm_ex_bkis.html).

A.2.6. In-State Base Year Generation Resource Performance and Cost Data

From the above EIA data, we have the generation, CO_2 emissions and fuel costs for each generating group. From that we can derive the average heat rate for each group and the fuel component of the generation costs. To that we add typical industry values for O&M. Also from that EIA data we have the historic capacity factors associated with resource group. Those historic patterns are used to set the basis for future performance.

A.2.7. New Generation Resource Performance and Cost Data

For new generation resources we have used the technology parameters from the AEO 2008 Assumptions document. For capital costs we have used our professional judgment based on a number of sources to reflect current cost expectations for new construction.

Fuel Types
We use the three basic fuel types as specified in the EIA documents (Coal, Petroleum and Natural Gas) with the addition of nuclear and biomass.

A.2.8. Annual Energy and Peak Load

For energy we have used the Reference Case customer sales forecast developed by ACEEE. We then apply a historic loss factor to arrive at the system energy load. To obtain the system peak load we have applied a historic system load factor to the above energy load. For VA we have used the load factor derived from the hourly loads at the PJM Dominion Hub in 2007.

Capacity Retirements
There is very little information about future plant retirements and a variety of unknown circumstances may either work in favor of or against individual plants. It is however likely that some older less efficient generation will be retired in the future. To reflect this we are representing modest gradual retirement of existing resources in the model inputs. But it is quite likely than many existing plants will be retrofitted and their lives extended.

Capacity Additions
In order to meet future load growth, new generation resources must be added to the existing generation mix.

The electricity model is not a capacity expansion model that optimizes capacity additions by choosing among a set of resource alternatives to develop a least cost expansion plan. Instead, we will add new resources "manually" to meet reserve needs. Our analysis will consider three sets of additions:

Planned Additions—Near-term proposed new additions or uprates to existing plants that are in development or advanced stages of permitting and have a high likelihood of reaching commercial operation;

RPS Additions—Renewable generators that are added to meet existing or anticipated renewable portfolio standards (RPS) in each state; and,

Generic Additions—New generic conventional resources that are added to meet the residual capacity need after adding planned and RPS additions.

Planned Additions
Description: Our near-term entry forecast is based on projects in development or advanced stages of permitting, trade press, environmental permit applications, and internal knowledge. The VEPCO FERC Form 1 filing of 2007 Q4 lists several near term NG CT units, a NG CC unit for 2011, a coal unit for 2012 and a possible new nuclear unit sometime in the next 20 years.
Data Sources: FERC filings, Virginia Energy Plan.

RPS Additions
In April 2007 the Virginia Department of Mines, Minerals and Energy (DSIRE) established a voluntary renewable energy portfolio goal starting at 4% (of 2007 levels) in 2010 and increasing to 12% in 2022. The mix is only loosely specified with wind and solar earning double credit. In checking the existing resources it appears that the 2010 goal is pretty much met by the resources currently in place. For new additions we assume that the larger majority will be wind with modest and increasing amounts of solar and biomass in the future.

The operating characteristics are based on AEO 2008 and Synapse estimates based on experience elsewhere in the US.

Generic Additions
In order to reliably serve the forecasted load in the mid- to long-term portion of the forecast period, new generic additions will need to be added to the model. A range of generation technologies was initially considered for this purpose, including gas/oil-fired combined-cycle, gas/oil combustion turbines, conventional coal, IGCC[2], and nuclear. As mentioned above the currently proposed resources in Virginia are Nat Gas Combustion Turbine (NGCT), Nat Gas Combined Cycle (NGCC) and Coal Steam. Therefore, the generic additions will be those types of units and nuclear units will not be included.

Generic additions are made based on meeting a system-wide reserve target including out-of –state resources of 15%. For the generic additions we use a mix of 45% conventional coal, 35% NGCC and 20% gas peakers.

A.2.9. Fuel Prices

We start with fuel prices reported for the base year of 2007. We used several sources to reflect current prices through mid 2008, and expectations for the future.

For natural gas we use NYMEX futures as of August 11, 2008 to scale natural gas prices out for the next twelve years. After that point we apply the relative price trends from the AEO 2008 modeling. (This is a change from our initial forecast, which was based on NYMEX futures as of mid-June. because of the dramatic change in futures over that two month period.)

We set petroleum prices at a historically determined multiple of natural gas prices. For coal we use the reported base year cost scaled by the relative year to year changes from AEO 2008.

A.2.10. Purchased Power Costs

Historic purchased power costs were obtained from the VEPCO FERC Form 1 filing for 2007 (Q4). Future purchased power costs are assumed to increase at the same rate as in-state power production costs.

A.2.11. Carbon Emission Costs

Carbon compliance costs were set at zero as requested by the ACEEE and the stakeholder group. Synapse Energy Economics considers it unrealistic to rely upon projections that exclude the cost of compliance with anticipated CO_2 emission regulations.

A.3.Electricity Planning and Costing Model

This model was developed by Synapse for ACEEE's clean energy state studies.

[2] Integrated gasification combined cycle

A.3.1. Background

ACEEE has initiated a series of state-specific "Clean Energy" potential studies through which it will work with key stakeholders in order to build a common understanding of, and consensus on, the role that clean energy resources, i.e., energy efficiency and demand response, can play in meeting the future electricity end-use requirements in each state, the economic benefits of treating those resources as the "first fuel" for meeting future requirements and the policies for maximizing reliance upon those resources. The time horizon for the studies is through 2025.

In each of those studies ACEEE will evaluate the cost effectiveness of reductions from energy efficiency and demand response, and will also demonstrate the benefits of those reductions to all consumers in the state by estimating retail prices in the long-term under a clean energy Policy Case.

ACEEE retained Synapse to provide three deliverables to support these studies

- projections of long-term wholesale electricity supply prices under a reference, or business-as-usual case;
- credible, consistent, "high-level" estimates of avoided electric energy ($/kWh) and capacity costs ($/kW-year); and
- projections of long-term electricity supply prices under a clean energy policy case.

In light of time and budget constraints, and the policy nature of these studies, ACEEE requested that Synapse develop and apply an electricity planning and costing model that would produce accurate "high-level" estimates of each of these deliverables in a well-documented, transparent manner.

In order to satisfy the ACEEE request, Synapse had to develop an electricity planning and costing model that would be:

- applicable to planning and costing from a state perspective, although most electric utility operations cross state boundaries;
- applicable from state to state, although some states are part of deregulated multi-state markets while others operate under traditional utility regulation;
- applicable using public data;
- inexpensive to setup and run; and
- relatively transparent.

Synapse has developed an EXCEL based planning and costing model with these characteristics.

A.3.2. Methodology

The model begins with an analysis of actual physical and cost data for a base year, develops a plan for meeting projected physical requirements in each future year of the study period and then calculates the incremental wholesale electricity costs associated with that plan. (Incremental to electricity supply costs being recovered in current retail rates).

A.3.3. Base Year Data

The actual data for the base year, and prior years, provides our starting point. That dataset contains historical data in the following categories:

1. Recent year summary statistics.
2. Listing of the ten largest plants in the state.
3. Top five providers of retail electricity
4. Electric capability by primary energy source.

5. Generation by primary energy source.
6. Fuel prices and quality.
7. Emissions.
8. Retail sales and revenues by customer class.
9. Retail sales by various provider types.
10. Supply and distribution of electricity.

This data enables us to characterize the electric supply system and its costs for a given state. For example the capacity, generation and capacity factor, average heat rate and fuel costs for different classes of resources. We can also calculate the retail margin from this data, i.e. the margin between average retail rates and variable production costs. The retail margin reflects the transmission and distribution costs being recovered in retail rates plus the fixed generation costs being recovered in those rates. This data is a very broad brush since the resources are grouped by fuel type and their operation is not characterized in great detail.

A.3.4. Future Years

We begin with the forecast of annual demand and energy in each future year provided by the ACEEE stakeholder group.

Next we develop a physical plan to meet the load in each of those future years. This is done in the model via the following steps:

1. Derive annual capacity and generation requirements from forecast of retail annual demand and energy, and reserve margins,
2. Determine the relative quantities of annual capacity and generation to be provided by in-state and out-state resources based on the current mix of in-state and out-of state resources,
3. Estimate resource retirements. It is quite difficult to predict the timing of actual plant retirements, but it is reasonable to assume that some older facilities will be retired during the study period. We assume gradual retirement of existing resources over time based on typical operating lifetimes. This is explicitly specified in the input data section and can easily be modified if more specific data becomes available.
4. Estimate the capacity, timing and timing of new generation additions, in-state and out of state. Our model is not a capacity expansion model and therefore does not make capacity additions "automatically". Instead, after we include "planned" capacity additions, we add enough "generic" capacity additions to maintain the reserve margin. Our generic additions are a mix of peaking, intermediate and baseload units that maintains the historical mix of those categories in the state. This approach is transparent as the additions are explicitly specified in the input data section.
5. Calculate the quantity of annual generation from each category of capacity, existing and new, in-state and out of state. The estimated quantity of generation from each category of capacity is derived from the operating capacity factors. These are generally based upon economic dispatch, i.e. dispatch from each category in order of increasing variable production costs

A.3.5. Calculate Production Costs

The model calculates the production costs for the particular plan via the following steps:

1. Calculate total cost of generation from existing in-state resources, purchases from out-of-state resources, and new in-state resources. This is a projection of total unit production costs, i.e. levelized capital costs plus current operating costs, for generation from each of the three major categories of resources: existing generation, new generation and imports. The production costs of existing in-state generation includes variable operating costs plus fixed

costs. The cost of generation from these resources decline over time as existing coal, oil and gas plants are retired, while the existing nuclear plants with low operating costs continue operation. The cost of power imported from out-of-state is indexed to the generation-weighted average cost of generation from in state resources, i.e., existing and new.

2. Apply the levelized capital cost for new capacity additions to calculate the full cost of energy from these resources.
3. Apply retail margin to estimate average retail price.

A.3.6. Calculate Avoided Costs

Finally, the model estimates the avoided costs via the following steps:

1. Calculate the total costs of the resources that would be avoided. These avoided resources and their avoided costs include avoided dispatch from existing in-state resources, i.e. variable operating costs, and avoided construction and dispatch of new in-state resources, i.e. capital costs and variable operating costs. In the first five years the avoided costs are a mix of avoided dispatch of existing resources and avoided total cost of new resources that would otherwise come-on-line during that period. The percentage of new resources included in that mix is phased-in, starting at 0% in year 1 and rising to 100% in year 5. After year 5 the avoided costs in each year equal the average total costs of new resources in that year. This calculation assumes that the capital costs of new resources are avoidable either through avoiding their actual construction or through recovery from revenues from off-system sales.
2. Calculate avoided capacity cost based upon cost of a new gas combustion turbine "peaker" unit. Basing avoided capacity cost on the capital cost of a new peaker is a commonly accepted method. This is expressed in both a capacity and an energy basis.
3. Calculate energy-only avoided cost. Taking the costs in step 9 above which include both operating and capital costs and subtracting the capacity costs from step 10 gives the equivalent energy-only avoided cost

A.4.Reference Case Electricity Supply Prices and Avoided Costs

This section presents Synape's projections of *Reference Case* electricity supply prices and avoided costs for Virginia. The projections are outputs from the electricity costing model that Synapse Energy Economics has developed for this project. The inputs to the model, and the structure of the model, are described above.

A.4.1. Reference Case Electricity Supply Prices

The reference case load forecast, supply forecast, and supply prices are presented in Table A-4. The supply forecast exceeds the load forecast by the level of estimated losses in transmission and distribution. The supply prices include the projected incremental generation costs each year, the retail margin each year and the resulting total average retail rate.

A.4.2. Avoided Electricity Costs

The avoided costs are presented in Table A-5. The avoided capacity costs are presented in $/kW-year while the avoided electric energy costs are given in ¢/kWh.

Table A-4 Reference Case Load, Supply and Price Forecasts

All costs in constant 2006 dollars.																		
CASE:	VA Reference Case - 9/5/08																	
Category	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load Forecast																		
Retail Energy	GWh	114,975	117,351	119,245	121,460	122,947	124,957	126,833	129,143	130,657	132,322	133,825	135,823	136,945	138,563	140,150	142,157	144,195
Retail Demand	MW	23,864	24,357	24,750	25,210	25,518	25,936	26,325	26,804	27,119	27,464	27,776	28,191	28,424	28,759	29,089	29,505	29,928
Supply Forecast																		
Capacity Requirement	MW	30,026	30,646	31,141	31,719	32,107	32,633	33,122	33,726	34,121	34,556	34,948	35,470	35,763	36,186	36,600	37,124	37,656
Capacity Sources																		
In-State Capacity	MW	22,918	22,689	23,180	23,655	23,745	23,788	24,060	24,175	24,546	24,218	24,460	24,367	24,001	23,636	23,585	23,664	23,807
Out-of-State Capacity	MW	7,108	7,957	7,961	8,064	8,362	8,845	9,063	9,550	9,575	10,338	10,489	11,103	11,762	12,550	13,015	13,460	13,849
Total Capacity Provided	MW	30,026	30,646	31,141	31,719	32,107	32,633	33,122	33,726	34,121	34,556	34,948	35,470	35,763	36,186	36,600	37,124	37,656
Energy Requirement	GWh	125,795	128,394	130,467	132,890	134,516	136,716	138,768	141,296	142,953	144,774	146,419	148,605	149,832	151,602	153,338	155,535	157,764
Energy Sources																		
In-State Generation	GWh	79,225	78,282	81,280	84,698	87,258	88,791	91,577	93,509	96,976	96,615	99,379	107,405	106,841	106,277	107,434	109,308	111,529
Out-of-State Generation	GWh	46,570	50,112	49,187	48,191	47,258	47,925	47,191	47,787	45,976	48,159	47,039	41,200	42,991	45,325	45,904	46,226	46,236
Total Energy Provided	GWh	125,795	128,394	130,467	132,890	134,516	136,716	138,768	141,296	142,953	144,774	146,419	148,605	149,832	151,602	153,338	155,535	157,764
Supply Price Forecast																		
Average Production Cost	¢/kWh	6.25	6.29	6.35	6.36	6.35	6.37	6.42	6.47	6.53	6.57	6.62	6.80	6.83	6.92	6.99	7.07	7.15

Table A-5 Reference Case Avoided Costs

All costs in constant 2006 dollars.																		
CASE:	VA Reference Case - 9/5/08																	
Category	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Avoided Costs by costing period																		
Avoided Resource Cost	¢/kWh	5.50	6.17	6.75	7.27	7.61	8.07	8.00	7.94	7.91	7.92	7.90	8.11	8.11	8.16	8.17	8.19	8.22
Avoided Capacity Cost	$/kW-yr	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06
	¢/kWh	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43
Avoided Energy Only Cost	¢/kWh	4.06	4.74	5.32	5.84	6.18	6.64	6.56	6.51	6.48	6.49	6.47	6.68	6.68	6.73	6.74	6.76	6.78
Notes:	Avoided Resource Costs represent avoided production costs (fuel, O&M, CO2) for all resources, plus levelized capital costs for new resources.																	
	Avoided Capacity Cost in $/kw-yr is converted into an energy cost equivalent (c/kWh) using the system load factor.																	
	Avoided Energy Cost represents Total Avoided Resource Cost less Avoided Capacity Cost expressed as energy cost equivalent.																	

A.5.Policy Case Electricity Supply Prices and Avoided Costs

This section presents Synapse's projections of *Policy Case* electricity supply prices and avoided costs for Virginia. The projections are outputs from the electricity costing model that Synapse has developed for this project as discussed above. ACEEE provided the Policy Case Load Forecast.

A.5.1. Policy Case Electricity Supply Prices

The Policy Case load forecast, supply forecast, and supply prices are presented in Table A-6. The supply forecast exceeds the load forecast by the level of estimated losses in transmission and distribution. The supply prices include the projected incremental generation costs each year, the retail margin each year and the resulting total average retail rate.

A.5.2. Avoided Electricity Costs

The avoided costs are presented in Table A-7. The avoided capacity costs are presented in $/kW-year while the avoided electric energy costs are given in ¢/kWh.

Table A-6. Policy Case Load, Supply and Price Forecasts

All costs in constant 2006 dollars.																		
CASE:	**VA Policy Case - 9/5/08**																	
Category	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load Forecast																		
Retail Energy	GWh	114,567	116,250	117,128	117,823	117,262	117,078	117,190	117,700	117,176	116,905	116,497	116,502	115,614	115,351	115,356	116,076	117,113
Retail Demand	MW	23,782	24,138	24,330	24,488	24,396	24,383	24,427	24,550	24,468	24,432	24,367	24,390	24,226	24,192	24,208	24,369	24,593
Supply Forecast																		
Capacity Requirement	MW	29,923	30,371	30,612	30,811	30,695	30,679	30,735	30,889	30,786	30,741	30,660	30,687	30,482	30,439	30,459	30,662	30,944
Capacity Sources																		
In-State Capacity	MW	22,918	22,589	22,780	22,955	23,045	22,636	22,349	22,236	22,195	21,830	21,464	21,098	20,733	20,367	20,001	19,636	19,606
Out-of-State Capacity	MW	7,005	7,781	7,833	7,856	7,650	8,044	8,386	8,654	8,591	8,911	9,196	9,589	9,750	10,072	10,458	11,026	11,338
Total Capacity Provided	MW	29,923	30,371	30,612	30,811	30,695	30,679	30,735	30,889	30,786	30,741	30,660	30,687	30,482	30,439	30,459	30,662	30,944
Energy Requirement	GWh	125,348	127,190	128,151	128,911	128,297	128,095	128,219	128,776	128,202	127,906	127,459	127,466	126,494	126,207	126,211	126,999	128,134
Energy Sources																		
In-State Generation	GWh	79,225	78,195	80,930	84,085	86,645	85,701	85,430	86,108	87,326	86,761	86,197	85,633	85,068	84,504	83,940	83,375	84,651
Out-of-State Generation	GWh	46,123	48,995	47,221	44,826	41,652	42,395	42,789	42,669	40,877	41,145	41,263	41,833	41,426	41,703	42,272	43,624	43,483
Total Energy Provided	GWh	125,348	127,190	128,151	128,911	128,297	128,095	128,219	128,776	128,202	127,906	127,459	127,466	126,494	126,207	126,211	126,999	128,134
Supply Price Forecast																		
Average Production Cost	6.26	6.24	6.26	6.27	6.23	6.19	6.15	6.16	6.18	6.21	6.22	6.24	6.28	6.29	6.35	6.40	6.47	6.57

Table A-7 Policy Case Avoided Costs

All costs in constant 2006 dollars.

CASE:	VA Policy Case - 9/5/08																	
Category	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Avoided Costs by costing period																		
Avoided Resource Cost	¢/kWh	5.50	6.17	6.75	7.07	7.33	7.73	7.74	7.73	7.76	7.80	7.84	7.89	7.92	7.99	8.05	8.11	8.16
Avoided Capacity Cost	$/kW-yr	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06
	¢/kWh	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43
Avoided Energy Only Cost	¢/kWh	4.06	4.74	5.32	5.64	5.90	6.30	6.30	6.30	6.33	6.37	6.41	6.46	6.49	6.56	6.62	6.68	6.73

Notes: Avoided Resource Costs represent avoided production costs (fuel, O&M, CO2) for all resources, plus levelized capital costs for new resources.
Avoided Capacity Cost in $/kw-yr is converted into an energy cost equivalent (c/kWh) using the system load factor.
Avoided Energy Cost represents Total Avoided Resource Cost less Avoided Capacity Cost expressed as energy cost equivalent.

Appendix B - Energy Efficiency Policy Scenarios

B.1. Electricity Savings, Peak Demand Reductions, and Costs from Policy Scenarios

B.1.1. Low-Case Policy Scenario

Table B-1. Electricity Savings in Low-Case Policy Scenario (GWh)

	Policy/Program	2010	2015	2020	2025	% Savings in 2025 (relative to forecast)
1	Energy Efficiency Resource Standard	857	4,791	8,980	10,656	7%
2	Building Energy Codes	-	379	880	1,354	1%
3	Appliance Efficiency Standards (Federal)	107	2,147	3,624	4,741	3%
	Total Savings	964	7,317	13,484	16,750	12%
	Adjusted Forecast	116,387	119,516	122,340	127,445	
	% Savings (cumulative)	1%	6%	10%	12%	
Notes						
1	Assumes savings of 10% by 2022, relative to 2006 consumption. Annual savings start at 0.25% in Yr 1, 0.5% in Yr 2, 0.5% in Yr3, relative to prior-year sales, and interpolate to reach 10% by 2022. For technology costs by sector, we assume first-year investment costs of $0.34, $0.17, and $0.29 per kWh for the residential, commercial, and industrial sectors, respectively, at the time of measure adoption or implementation.					
2	Assumes the IECC 2009 is adopted, which goes into effect 2011. We estimate that this code will be a 15% energy savings improvement beyond IECC 2006 requirements. Savings apply only to end-uses covered under building codes, which are HVAC, lighting, and water heating end-uses. We assume enforcement of the codes starts at 70% compliance in the first year, 80% in second year, and 90% in subsequent years. Based on the buildings analysis, we assume a $0.62 per kWh investment cost at the time of construction for new residential buildings that comply with the new code and $0.20 per kWh for new commercial buildings. We assume $1.5 million dollars per year to implement and enforce codes, based on recommendations in New York (NY DPS 2007). This is similar to estimates in VA that new program costs run 2-3% of building costs.					
3	Appliance and equipment efficiency standards were adopted at the federal level in the 2007 energy bill, which also directed DOE to set standards for additional products in the coming years. This Scenario assumes savings from these standards, which are not taken into account in the reference case load forecast. Savings and cost assumptions are from a forthcoming ACEEE and ASAP standards analysis.					
	Savings by Sector					
	Residential	352	2,929	5,371	6,725	5%
	Commercial	425	3,129	5,809	7,231	5%
	Industrial	186	1,259	2,303	2,795	2%
	Total Savings	964	7,317	13,484	16,750	12%

Table B-2. Summer Peak Demand Reductions in Low-Case Scenario (MW)

	2010	2015	2020	2025	
Residential	77	644	1,182	1,479	5%
Commercial	102	751	1,394	1,735	5%
Industrial	26	176	322	391	1%
Total Savings	206	1,572	2,898	3,606	11%
% Reduction (relative to forecast)	1%	5%	9%	11%	

Table B-3. Total Resource Costs* in Low-Case Scenario (Million 2006$)

Policy/Program	2010	2015	2020	2025
Energy Efficiency Resource Standard	$160	$234	$234	$0
Building Energy Codes	$0	$43	$42	$36
Appliance Efficiency Standards (Federal)	$16	$154	$189	$189
Total Costs	$176	$431	$465	$225

*Note: Total Resource Costs include total investments in energy efficiency, whether made by customers or through incentives, plus program and administrative costs.

B.1.2. Medium-Case Policy Scenario

Table B-4. Electricity Savings in Medium-Case Policy Scenario (GWh)

	Policy/Program	2010	2015	2020	2025	
1	Energy Efficiency Resource Standard	**857**	**6,477**	**13,216**	**18,437**	13%
2	*Clean Distributed Generation Policies*	*44*	*504*	*1,075*	*1,394*	*1%*
3	*State Manufacturer Initiative*	*25*	*850*	*1,864*	*2,883*	*2%*
4	State Facilities	58	205	351	497	0.3%
5	Local Government Facilities	117	409	702	994	1%
6	Building Energy Codes	-	595	1,720	2,821	2%
7a	Appliance Efficiency Standards (Federal)	107	2,147	3,624	4,741	3%
7b	Appliance Efficiency Standards (State)	5	125	279	425	0%
	Total Savings	1,144	9,957	19,892	27,914	19%
	Adjusted Forecast	116,207	116,876	115,932	116,281	
	% Savings (Total relative to forecast)	1%	8%	15%	19%	
	Notes					
1	Assumes savings of 15% by 2022, relative to 2006 consumption Annual savings start at 0.25% in Yr 1, 0.5% in Yr 2, 0.75% in Yr 3, 1% in Yrs 4 - 8, and about 1.1% in Yrs 9 - 17 to reach 15% by 2022 and 19% by 2025. Industrial sector savings and costs are those from CHP policies and the Manufacturing Initiative (see below). Residential and commercial sector cost assumptions are the same as Scenario One.					
2	This scenario assume that the effective cost of installing CHP is reduced by $500 per kW as a result of reduced project uncertainty and delays as a result of removal of market barriers as described in the text.					
3	This scenario assumes that the number of industrial assessments ramps up from 50 to 200 in first three years, that each assessment identifies 20% electricity savings, and that 50% of identified savings are implemented. Project costs assume the average investment cost per kWh from the industrial sector analysis ($0.29/kWh) and program cost is assumed to be 12.5% of projected cost savings to the end-user.					
4	This Scenario assumes that Virginia expands its Energy Savings Performance Contract (ESPC) program to complete projects in 50% of state facilities by 2025 and that projects achieve an average energy savings of 20%. Costs assume the average investment cost per kWh from the commercial sector analysis ($0.17/kWh).					
5	Assumes the same participation rate, savings, and costs as state facilities.					
6	Assumes the same as Scenario One, plus adoption of the IECC 2102 which go into effect in 2015. We estimate that the IECC 2012 achieves 30% energy savings improvement beyond IECC 2006 requirements. Compliance assumptions are the same as Scenario One, and apply at adoption of each new code. Cost assumptions are the same as Scenario One.					
7a	Same as Scenario One.					
7b	In addition to federal efficiency standards, this scenario assumes that Virginia adopts state-level standards for six products: DVD players, compact audio equipment, hot food holding cabinets, portable electric spas, water dispensers, and furnace fans.					
	Savings by Sector					
	Residential	382	3,562	7,078	9,787	7%
	Commercial	708	5,070	10,080	14,121	10%
	Industrial	54	1,325	2,733	4,006	3%
	Total Savings	1,144	9,957	19,892	27,914	19%

Table B-5. Summer Peak Demand Reductions in Medium-Case Scenario (MW)

	2010	2015	2020	2025	
Residential	84	784	1,557	2,153	7%
Commercial	169	1,194	2,368	3,318	10%
Industrial	9	191	394	577	2%
Total Savings	261	2,169	4,319	6,048	18%
% Reduction (relative to forecast)	1%	8%	14%	18%	

Table B-6. Total Resource Costs* in Medium-Case Scenario (Million 2006$)

Policy/Program	**2010**	**2015**	**2020**	**2025**
Energy Efficiency Resource Standard	$156	$331	$378	$382
Clean Distributed Generation Policies	*$8*	*$36*	*$24*	*$12*
State Manufacturer Initiative	*$8*	*$61*	*$62*	*$62*
State Facilities	$5	$5	$5	$5
Local Government Facilities	$10	$10	$10	$10
Building Energy Codes	$0	$69	$86	$75
Appliance Efficiency Standards (Federal and State)	$16	$161	$196	$196
Total Costs	$187	$575	$676	$668

*Note: Total Resource Costs include total investments in energy efficiency, whether made by customers or through incentives, plus program and administrative costs.

Table B-7. Electricity Savings in High-Case Policy Scenario (GWh)

		2010	2015	2020	2025	
1	Energy Efficiency Resource Standard	857	7,948	16,875	25,748	18%
2	*Clean Distributed Generation Policies*	*202*	*1,572*	*3,079*	*3,829*	3%
3	*State Manufacturer Initiative*	*25*	*925*	*2,193*	*3,467*	2%
4	State Facilities	88	307	526	746	1%
5	Local Government Facilities	175	614	1,052	1,491	1%
6	Building Energy Codes	-	424	1,408	2,884	2%
7a	Appliance Efficiency Standards (Federal)	107	2,147	3,624	4,741	3%
7b	Appliance Efficiency Standards (State)	5	125	279	425	0.3%
8	Energy Efficiency RD&D Initiative	-	29	294	3,083	2%
	Total Savings	1,232	11,593	24,060	39,117	27%
	Adjusted Forecast	**116,119**	**115,240**	**111,764**	**105,078**	
	% Savings (cumulative)	**1%**	**9%**	**18%**	**27%**	
1	Assumes 19% savings by 2022, relative to 2006 consumption. Annual savings, relative to prior-year sales, are 0.25% in Yr 1, 0.5% in Yr 2, 0.75% in Yr3, 1% in yr 4, 1.25% in yr 5, and 1.5% in yr 6 and remaining years to reach 19% cumulative by 2022. Industrial sector savings and costs are those from CHP policies and the Manufacturing Initiative (see below). Residential and commercial sector cost assumptions are the same as Scenario One.					
2	This scenario assumes that in addition to removal of barriers, CHP receives either directly or indirectly incentives that have the effect of reducing the installed cost of CHP capacity by $100 per kW.					
3	This scenario assumes that the number of assessments ramps up from 50 to 200 in first three years and then to 250 in year 5, that each assessment identifies 20% electricity savings and that 50% of identified savings are implemented. Project costs assume the average investment cost per kWh from the industrial sector analysis ($0.29/kWh) and program cost is assumed to be 12.5% of projected cost savings to the end-user.					
4	This Scenario assumes that Virginia expands its Energy Savings Performance Contract (ESPC) program to complete projects in 75% of state facilities by 2025 and that projects achieve an average energy savings of 20%. Costs assume the average investment cost per kWh from the commercial sector analysis.					
5	Assumes the same participation rate, savings, and costs as state facilities.					

		2010	2015	2020	2025	
6	Same as Scenario Two, plus adoption of a new code in 2018, effective 2021, that achieves 50% savings beyond the IECC 2006. Compliance assumptions are the same as Scenario One, and apply at adoption of each new code. Cost assumptions are the same as Scenario One, assuming that costs for new construction at this level of savings comes down to current costs of 15% and 30% beyond-code buildings.					
7a	Same as Scenario One.					
7b	Same as Scenario Two.					
8	This scenario assumes that Virginia invests in an RD&D effort specific to energy efficiency.					
	Residential	368	3,997	8,313	13,666	9%
	Commercial	774	5,948	12,196	19,906	14%
	Industrial	89	1,648	3,550	5,545	4%
	Total Savings	1,232	11,593	24,060	39,117	27%

Table B-8. Total Resource Costs* in High-Case Scenario (Million 2006$)

Policy/Program	**2010**	**2015**	**2020**	**2025**
Energy Efficiency Resource Standard	$156	$477	$484	$481
Clean Distributed Generation Policies	*$24*	*$82*	*$50*	*$22*
State Manufacturer Initiative	*$8*	*$76*	*$77*	*$78*
State Facilities	$8	$8	$8	$8
Local Government Facilities	$15	$15	$15	$15
Building Energy Codes	$0	$66	$83	$118
Appliance Efficiency Standards (Federal and State)	$16	$161	$196	$196
Energy Efficiency RD&D Initiative	$7	$9	$36	$305
Total Costs	$202	$736	$820	$1,123

*Note: Total Resource Costs include total investments in energy efficiency, whether made by customers or through incentives, plus program and administrative costs.

B.2.Carbon Dioxide Emissions Reductions

To estimate annual regional emissions reductions, we first took data on projected electricity generation and carbon dioxide emissions over the 2007-2025 period for the South-Eastern Reliability Council (SERC) region as reported by the *Annual Energy Outlook* (EIA 2007c). We then calculated an *output emission rate*, defined as the ratio of emissions (lbs) to electricity generation (MWh). Using data from the Emissions and Generation Resource Integrated Database (eGRID) on subregional emission rates and converting to standard tons (EPA 2007), we calculated a *net marginal emissions factor* (ton/MWh), which is our *output emission rate* multiplied by the ratio of marginal to average emission rates. We then took our *emissions factor* and multiplied by Virginia's estimated electricity savings (GWh) from Policy Scenario Two in order to determine the regional *carbon dioxide emissions savings* for the 18-year period.

Appendix C - Energy Efficiency Resource Assessment

C.1.Residential Buildings

C.1.1. Overview of Approach

We analyzed thirty-four electricity efficiency measures for existing residential buildings, which are grouped by end-use (HVAC, water heating, refrigeration, appliances, lighting, furnace fans, and plug loads) and three measures for new residential buildings (see Table A.1). For each measure, we estimated average measure lifetime, electricity savings (kWh) and costs per home upon replacement of the product or retrofitting of the measure. For a replacement-on-burnout measure,[3] the cost is the incremental cost of the efficient technology compared to the baseline technology. For retrofit measures, where existing equipment is not being replaced, such as improved insulation and infiltration reduction, the cost is the full installation cost of the measure. For measures modeled as replacement-on-burnout, the baseline is set according to the current market for that product, so the baseline efficiency is the minimum efficiency standard of that product. For measures modeled as retrofit, the baseline efficiency is that of estimated energy use in existing Virginia homes.

A measure is determined to be cost-effective if its levelized cost of saved energy, or cost of conserved energy (CCE), is less than 10.7 cents/kWh, the current average residential cost of electricity in Virginia (EIA 2008b). Estimated levelized costs for each efficiency measure, which assume a discount rate of 5%, are shown in Table C.1. Equation one shows the calculation for cost of conserved energy.

Equation 1. *CCE = PMT ((Discount Rate), (Measure Lifetime), (Measure Cost)) / (Annual Savings per Measure (kWh))*

[3] In a replacement-on-burnout scenario, a consumer purchases the more efficient product at the time of replacement of that product.

Table C.1 Residential Energy Efficiency Measure Characterizations

Measures	End-Use Category	Annual savings per household (kWh)	Cost of Saved Energy ($/kWh)	Pass Cost-Effective Test?	% Turnover	Adjustment Factor	Interaction Factor	% End Use Savings	Total Savings in 2025
Existing Building					**2025**		**2025**	**2025**	
Seal Ductwork	HVAC (load)	639	$ 0.09	yes	100%	50%	100%	10%	1039
Insulate Ductwork, R-8	HVAC (load)	639	$ 0.03	yes	100%	50%	90%	9%	937
Infiltration reduction	HVAC (load)	799	$ 0.01	yes	100%	40%	80%	8%	844
Insulation, ceiling, R-11 to R-38	HVAC (load)	703	$ 0.02	yes	100%	28%	70%	4%	455
Insulation, ceiling, R-19 to R-38	HVAC (load)	314	$ 0.05	yes	100%	41%	70%	3%	291
Blow-in wall insulation	HVAC (load)	1198	$ 0.03	yes	100%	16%	61%	4%	379
Estar Window, from single pane	HVAC (load)	2301	$ 0.01	yes	57%	24%	55%	5%	544
Estar Window, from double pane	HVAC (load)	575	$ 0.05	yes	57%	50%	55%	3%	289
Cool Roof shingles	HVAC (load)	413	$ 0.03	yes	85%	77%	40%	3%	355
HVAC Load Reducing Measures								**48%**	
Central HP (heating cycle); HSPF 9	HVAC (equipment)	606	$ 0.09	yes	94%	13%	52%	1%	128
GSHP w/ desuperheater (14 EER)	HVAC (equipment)	2684	$ 0.08	yes	94%	3%	52%	1%	114
Central AC (cooling cycle) SEER 15	HVAC (equipment)	269	$ 0.03	yes	94%	53%	52%	2%	224
ENERGY STAR Dehumidifier	HVAC (equipment)	213	$ 0.08	yes	100%	5%	52%	0%	19
Energy Star Room A/C (10.8 EER)	HVAC (equipment)	112	$ 0.05	yes	100%	32%	52%	1%	59
Ceiling Fan (including light kit)	HVAC (equipment)	313	$ 0.08	yes	100%	50%	52%	2%	263
HVAC Equipment Measures								**8%**	
TOTAL HVAC								**56%**	**5940**
High-efficiency showerheads	Water Heating	250	$ 0.01	yes	100%	27%	100%	6%	219
Faucet aerators	Water Heating	48	$ 0.02	yes	100%	29%	100%	1%	46
Water heater pipe insulation	Water Heating	65	$ 0.05	yes	100%	39%	100%	2%	83
H-axis clothes washer (2.0 MEF) (water heating)	Water Heating	232	$ 0.08	yes	100%	24%	100%	5%	180
Dishwasher (Electric WH; 0.68 EF) (water heating)	Water Heating	43	$ 0.06	yes	100%	23%	100%	1%	32
GSHP w/ desuperheater (14 EER)	Water Heating	627	$ 0.14	no	94%	27%	84%	12%	432

Measures	End-Use Category	Annual savings per household (kWh)	Cost of Saved Energy ($/kWh)	Pass Cost-Effective Test?	% Turnover	Adjustment Factor	Interaction Factor	% End Use Savings	Total Savings in 2025
Efficient electric water heater (0.93 EF)	Water Heating	81	$ 0.09	yes	100%	29%	84%	2%	63
Heat pump water heater (COP = 2.0)	Water Heating	1505	$ 0.06	yes	100%	16%	84%	18%	639
Water Heating Savings								**49%**	**1695**
Refrigerator (20%)	Refrigeration	114	$ 0.05	yes	89%	81%	100%	6%	330
Refrigerator (25%)	Refrigeration	29	$ 0.10	yes	89%	115%	100%	2%	117
Refrigeration Savings								**8%**	**447**
CFL, Advanced Incandescent Replacements	Lighting	1005	$ (0.00)	yes	100%	90%	100%	43%	2939
Lighting Savings								**43%**	**2939**
H-axis clothes washer (2.0 MEF)	Appliances	26	$ 0.08	yes	100%	53%	100%	2%	55
Dishwasher (Electric WH; 0.68 EF)	Appliances	11	$ 0.08	yes	100%	47%	100%	1%	21
Appliances Savings								**2%**	**76**
Efficient Furnace Fan (Heating Season)	Furnace Fans	322	$ 0.04	yes	94%	55%	100%	26%	666
Efficient Furnace Fan (Cooling Season)	Furnace Fans	164	$ 0.04	yes	94%	55%	100%	13%	339
Furnace Fan Savings								**39%**	**1005**
Active Mode Standard for TV	Plug Loads	183	$ 0.03	yes	100%	74%	100%	4%	133
Set-Top Box Power Reduction	Plug Loads	120	$ 0.03	yes	100%	58%	100%	2%	69
1-watt standby power	Plug Loads	264	$ 0.02	yes	100%	66%	100%	5%	698
Total Plug Load Savings								**11%**	**900**
In-home energy feedback monitor	All	1386	$ 0.02	yes	100%	67%	10%	1%	376
New Construction Building Measures									
New home 15% better than code (Energy Star home)	New Construction	962	$ 0.05	yes	100%	17%	100%	1%	67
New home 30% better than code (Proposed Building Code)	New Construction	1924	$ 0.05	yes	100%	35%	100%	5%	274
New home 50% better than code (Tax-credit-eligible)	New Construction	3207	$ 0.06	yes	100%	47%	100%	11%	608
New Homes Subtotal									**949**

C.1.2. Existing Buildings

To estimate the efficiency resource potential in existing homes in Virginia by 2025, we first adjusted individual measure savings by an *Adjustment Factor*. This factor accounts for the technical feasibility of efficiency measures (the percent of Virginia homes that satisfy the base case conditions and other technical prerequisites such as number of household members, heating fuel type, etc.) and the current market share of products that already meet the efficiency criteria. These assumptions are made explicit in Table B.2.

We then adjusted savings from the improved building envelope (insulation, windows, infiltration reduction, and duct sealing) to account for the reduced heating and cooling loads imparted by each of the envelope measures. Then we adjusted HVAC equipment savings to account for savings already realized from the reduced loads. Similarly, we adjusted water heating equipment savings to account for reduced water heating loads from the use of more efficient clothes washers, low-flow shower heads, water heater pipe insulation, and faucet aerators. The multiplier for these adjustments is called the *Interaction Factor.*

We then adjusted replacement measures with lifetimes more than 17 years to only account for the percent turning over in 17 years, which represents the time period of the analysis. Note that the multiplier, *Percent Turnover,* is only applicable to products being replaced upon burnout and not retrofit measures such as insulation and duct sealing and testing. These retrofit measures therefore have 100% of measures "turning over."

Equation 2 shows our calculation for efficiency resource potential, incorporating the three factors discussed above:

Equation 2. *Efficiency Resource Potential* = ∑ *(Annual Savings per Measure (kWh))* x *(Percent Turnover)* x *(Adjustment Factor)* x *(Interaction Factor)*

To calculate the efficiency resource potential savings by end-use in 2025, we present the savings as a percent of end-use electricity consumption (assuming current electricity consumption by end-use from AEO 2007). For the non-HVAC savings, we then multiply the "% savings" by projected residential electricity consumption for that end-use in 2025 to estimate the total savings potential in that year (see Equation 2). We assume that savings in the residential new construction sector cover projected new HVAC consumption, and therefore multiply the HVAC "% savings" by 2008 electricity consumption of this end use. See Equation 3 for a summary of how we derive the savings estimate for existing residential buildings.

Equation 3. *Efficiency Resource Potential by end-use in 2025 (GWh) = (% End-Use Savings)* x *(Electricity Consumption by sector in 2025* (GWh))*
* 2008 for HVAC

New Construction

We estimate savings from new construction in a similar manner as existing home measures. We looked at three levels of efficiency in new homes: 15%, 30%, and 50% better than current energy code. In estimating new home energy savings, we use a similar approach as building codes, which address HVAC consumption only. We estimated *% Applicable* by allocating each home into one of the three bins, with 15% predominating the early years and 50% the later years. See Equation four for a summary of how we calculate savings in new construction.

Equation 4. *Efficiency Resource Potential in 2025 (GWh) = (% HVAC savings per home) x (Percent Applicable) x (Projected new HVAC consumption between 2008 and 2025 (GWh))*

Measure Descriptions

In-home energy feedback monitor

Measure Description: A device installed inside the home that communicates with the electric meter and displays real-time electricity use information to occupants.

Basecase: Average metered home with no feedback mechanism other than monthly utility bills

Data Explanation. Total households applicable (67%) from RECS 2005 (EIA 2008b). Baseline electricity consumption is for an average household excluding multifamily buildings above four units from RECS (EIA 2003). Cost includes cost of product ($150) plus one hour of installation from Parker (2006). Percent savings (10%) from Stein (2004) and Hydro One (2006). Useful life (11 years) assumed to be similar to programmable thermostat, from ACEEE (2006). Penetration in residential sector technically achievable in all metered residential units.

Duct Sealing

Measure Description: Professional duct-sealing service suitable for retrofits and new construction, involving testing and either hand-applied or aerosol-based mastic (Jump 2006).

Basecase: Single-family home with a forced-air furnace and air conditioner.

Data Explanation: Baseline energy use from RECS (EIA 2003) depending on primary fuel use, plus a 25% adder representing high-use homes. Savings of 10% in each season (cooling and heating) is derived from 80% reduction in duct leakage (Jump 1996), which comprises half of the 20% of total HVAC energy use that can be associated with duct-related energy losses (the other half being by conduction, [Hammurlund 1992; Proctor 1993]). A cost of $750 is mature-market cost of Aeroseal, from Bourne, et al 1999. Applies to top 50% of residential homes with forced-air systems. Measure life is 20 years (SWEEP 2002)

Duct Insulation

Measure Description: R8 insulation applied to exposed ductwork in unconditioned spaces.

Basecase: Single-family home with a forced-air furnace and air conditioner with uninsulated ductwork passing through un-conditioned space (attic, un-finished basement, garage)

Data Explanation: Baseline energy use from RECS 2001 (EIA 2003) depending on primary fuel use, plus a 25% adder representing high-use homes. Savings from SWEEP, based on 10% heating/cooing energy use in forced-air system associated with conductive duct losses. Cost are $0.15–$0.20 per square foot of floor area. Floor area (1800 sq. ft) based off average floor area of colonial and ranch single family detached from ACEEE 1994. Applies to top 50% of residential homes with forced-air systems. Useful life is 25 years (SWEEP 2002).

Blower-Door Aided Infiltration Reduction

Measure Description: Application of foam and/or caulk around leakage areas applied and tested by a professional using a blower-door.

Basecase: Household with higher-than average heating and cooling energy use.

Data Explanation: Baseline energy use from RECS (EIA 2003) depending on primary fuel use, plus a 25% adder representing high-use homes. Savings of 10% from MT Screening Reports. Cost of $0.46/s.f. from XENERGY (2001). Useful life of 10 years from SWEEP 2002. Savings applied to percentage of homes that report drafts (40%), from RECS (EIA 2003).

Attic Insulation

Measure Description: Add insulation in attic floor to R-38.

Basecase: R-11 assumed for houses reported to be "well insulated."

Data Explanation: Savings average of colonial and ranch savings for R11-R30 attic insulation from NYSERDA 1994, increased by multiplier (1.09) to incorporate savings from upgrading to R38. Total households applicable

(28%) average from RECS 2005 for house that are "well insulated" and houses that are "not well insulated" (EIA 2008b). Baseline energy use from RECS 2001 (EIA 2003) depending on primary fuel use, plus a 25% adder representing high-use homes.. Cost of $0.86/s.f. from DEER database (CEC 2005). Assumes 1000 s.f. of insulation needed. Useful measure life of 20 years from NYSERDA 2003.

Attic Insulation

Measure Description: Add insulation in attic floor to R-38.

Basecase: R-19 assumed for houses reported to be "well insulated."

Data Explanation: Savings average of colonial and ranch savings for R19-R30 attic insulation from NYSERDA 1994, increased by multiplier (1.34) to incorporate savings from upgrading to R38. Total households applicable (41%) from RECS 2005 for house that are "well insulated" (EIA 2008b). Baseline energy use from RECS 2001 (EIA 2003) depending on primary fuel use, plus a 25% adder representing high-use homes.. Cost of $0.86/s.f. from DEER database (CEC 2005). Assumes 1000 s.f. of insulation needed. Useful measure life of 20 years from NYSERDA 2003.

Blow-in Cellulose Wall Insulation
Measure Description: Add blow-in cellulose insulation to un-insulated wall cavities

Basecase: Average-sized single-family home with wood-frame construction built before 1970.

Data Explanation: Total households applicable (16%) from RECS 2005 for houses that are "not well insulated" (EIA 2008b). Baseline energy use from RECS 2001 (EIA 2003), depending on primary fuel use, plus a 25% adder representing high-use homes. Savings of 15% and 1700 s.f. of uninsulated wall space are based on average of colonial and ranch single-family detached house types from 1994 ACEEE study on Gas EE opportunities in Long Island. Cost of $0.32/s.f. (unit and installation cost) from DEER database (CEC 2005). Useful measure life of 30 years from NYSERDA 2003.

Cool Roof Shingles
Measure Description: Roof shingles that meet ENERGY STAR residential requirements for reflectivity and thermal emittance due to light color or other material properties.

Basecase: Standard high-pitched residential roof with dark asphalt shingles

Data Explanation: Baseline electricity reflects cooling load only, from RECS 2001 (EIA 2003). Savings of 20% of cooling load and cost ($.10/s.f.) are from ACEEE Emerging Technologies analysis (Sachs et al 2004). Roof area (1400 sq. ft) based off assumption of 1000 sq. ft for attic area, multiplied by 1.4 (roof area generally 1.4 times greater than the area of the attic). Percent of homes applicable (86%) are the percent of households with asphalt shingles, from Dejarlais (2006). Market share (10%) and measure life (20 years) are from Sanchez et al. (2007).

ENERGY STAR Windows

Measure Description: Window replacements that meet regional ENERGY STAR requirements for U value and solar heat gain coefficient (SHGC).

Basecase: Replacement of 20 *single-pane* windows measuring approximately 15 s.f. each.

Data Explanation: Baseline energy use from RECS 2001 (EIA 2003). Savings (36%) from ratio of U-values associated with upgrading from single pane (U-value = 1.10) to Energy Star (U-value = .40), from Lekcie et al. 1981. Number of units (20) from ACEEE (2006). Incremental cost assumes 300 sq. ft. of windows at $1.50 per sq. ft. (NEEP 2006). Measure life (30) from SWEEP 2002. Percent of applicable households (50%) based on ENERGY STAR market share data.

High-efficiency Central Air Conditioner (cooling only)
Measure Description: SEER 15

Basecase: Current federal standard: SEER 13

Data Explanation: Baseline consumption from RECS 2001 (EIA 2003). Percent savings (13%) and incremental cost from Energy Star calculator for Central Air Conditioners using Richmond, VA, as a proxy. Assumed not to be used in conjunction with programmable thermostat. Market share (9%) from Sanchez et al. (2007), assumed to be half of market share for Energy Star qualified unit with SEER = 14. Measure life (18 years) from DOE TSD (DOE 2001).

High-efficiency Heat Pump (heating only)
Measure Description: HSPF 9

Basecase: Current federal standard: HSPF 7.7

Data Explanation: Baseline consumption from RECS 2001 (EIA 2003). Percent savings (14%) and incremental cost ($630) from Energy Star calculator for Air-Source Heat Pumps using Richmond, VA, as a proxy and apportioned based on heating hours for Richmond, VA. Assumed not to be used in conjunction with programmable thermostat. Market share (11%) from Sanchez et al. (2007), assumed to be half of market share for Energy Star qualified unit with HSPF = 8.2. Measure life (18 years) from DOE TSD (DOE 2001).

Efficient Furnace Fan (heating season)
Measure Description: High efficiency, ECM fan

Basecase: PSC fan

Data Explanation: Baseline electricity consumption from Lutz (2004), accounting for parasitics and adjusted by ratio of national to state HDD. Electricity savings (322 kWh, 60%) from Pigg (2008) and adjusted by ratio of national to state HDD. Incremental costs ($200) from Sachs & Smith 2004, apportioned by ratio of seasonal savings, although report notes that incremental costs will drop to $25-$45 upon market maturity. Incremental costs apportioned for heating season from ratio of heating season savings to total annual savings.

Efficient Furnace Fan (cooling season)
Measure Description: High efficiency, ECM fan

Basecase: PSC fan

Data Explanation: Baseline electricity consumption from Lutz (2004), accounting for parasitics and adjusted by ratio of national to state CDD. Electricity savings (164 kWh, 22%) from Pigg (2008) and adjusted by ratio of national to state CDD. Incremental costs ($200) from Sachs & Smith 2004, apportioned by ratio of seasonal savings, although report notes that incremental costs will drop to $25-$45 upon market maturity. Incremental costs apportioned for cooling season from ratio of cooling season savings to total annual savings.

Ground-Source Heat Pump
Measure Description: Closed ground-source heat pump with EER 14.

Basecase: Conventional air-source heat pump of SEER 13, HSPF 7.7

Data Explanation: Baseline energy use (for homes with electricity as primary fuel multiplied by 2 for high-use homes) and market penetration (of heat pumps) from RECS 2001(EIA 2003).New measure savings (21%) and cost ($2400) from ACEEE Emerging Technologies analysis (Sachs 2007). Analysis assumes technical feasibility in 10% of houses with forced-air electric heat. Measure life (18 years) from Sachs 2007.

Ground-Source Heat Pump with Desuperheater (water heating only)
Measure Description: HSPF 9

Basecase: Current federal standard: HSPF 7.7

Data Explanation: Baseline energy use and market penetration (of heat pumps) from RECS 2001 (EIA 2003). New measure savings (25%) and cost ($1,000) from ACEEE Emerging Technologies analysis (Sachs 2007). Analysis assumes technical feasibility in 10% of houses with electric forced-air heat. Measure life (18 years) from Sachs 2007.

Efficient Electric Storage Water Heater
Measure Description: 50-gallon electric storage water heater, 0.93 EF

Basecase: Current federal standard for typical, 50-gallon electric storage water heater, 0.90 EF

Data Explanation: Baseline consumption from GAMA water heater directory. Savings (3%) derived from EF increase. Incremental cost ($70) from Amann et al. (2007). Measure life (14 years) from NYSERDA 2003. Applies to houses with electric water heaters (EIA 2003). Market share (36%) estimated based on percent of products on the market meeting EF 0.93 in the GAMA product database (GAMA 2007).

Heat Pump Water Heater
Measure Description: Either add-on or integrated heat-pump that uses the evaporation-compression cycle to extract heat from surrounding air to heat water in a conventional storage tank. COP 2.0 or above.

Basecase: Current federal standard for typical, 50-gallon electric storage water heater, 0.90 EF

Data Explanation: Baseline consumption from GAMA water heater directory. Percent Savings (60%) and measure life (14.5 years) are from Sachs, et al 2004. Incremental cost ($910) based off electric heat pump with COP=2.2, from Amann et al. (2007). Percent of households applicable (45%) include percentage of households with electric water heating multiplied by percentage of households that have three or more occupants.

High-efficiency showerheads
Measure Description: 2.0 gallons per minute (gpm) showerhead

Basecase: Assumes electric water heater meeting current federal standard (see Electric Storage Water heater above). Showerhead meets federal requirements of 2.5 gpm

Data Explanation: Baseline consumption from RECS 2001 (EIA 2003) depending on primary water heating fuel. Savings (10%) from Brown, et al 1987. Cost estimate ($23) for a low-cost, basic model from the DEER database (CEC 2005). Useful measure life of 9 years from Efficiency Vermont (2005). Percent of households applicable (45%) is percentage of households with electric water heating (average of Mid and South Atlantic), adjusted for current market share (40%) from BG&E customer appliance saturation survey.

Faucet Aerators
Measure Description: 1.5 gallons per minute (gpm) faucet aerator

Basecase: Assumes electric water heater meeting current federal standard (see Electric Storage Water heater above). Baseline aerator meets federal requirements of 2.5 gpm

Data Explanation: Baseline consumption from RECS 2001 (EIA 2003) depending on primary water heating fuel. Savings (2%) from Frontier Associates (2006). Cost estimate ($7) for a low-cost, basic model from the DEER database (CEC 2005). Percent of homes applicable (45%) is based on water heating fuel analyzed RECS 2001(EIA 2003), adjusted for current market share (35%) from BG&E customer appliance saturation survey.

Water Heater Pipe Insulation
Measure Description: Insulating 10 feet of exposed pipe in unconditioned space, ¾" thick.

Basecase: Assumes electric water heater meeting current federal standard (see Electric Storage Water heater above).

Data Explanation: Baseline consumption from RECS 2001 (EIA 2003) depending on primary water heating fuel. Savings estimate from CL&P 2007. Costs ($28) from DEER Database based off $0.37 per linear foot equipment cost and $2 per linear foot installation cost (CEC 2005). Useful life of insulation 13 years from Efficiency Vermont (2005). Percent of homes applicable is based on water heating fuel analyzed.

Efficient Dehumidifier
Measure Description: Replacement dehumidifier that is ENERGY STAR certified based on the 2008 Energy Star specification.

Basecase: Dehumidifier that meets current (2005) federal energy standards.

Data Explanation: Baseline and incremental costs ($150) and electricity consumption from ENERGY STAR calculator. Percent savings (19%), measure life (12 years), and market share (60%) from Sanchez et al. (2007).

Efficient Room Air Conditioner

Measure Description: Energy Star Room A/C (10000 Btu unit at 10.8 EER).

Basecase: Room A/C that meets 2000 federal energy standards (10000 Btu at 9.8 EER)

Data Explanation: Baseline consumption, savings, and incremental cost from Energy Star savings calculator. Percent homes applicable (33%) based on saturation data and number of units per home from RECS 2005 (EIA 2008b). Measure life (13 years) from Sanchez et al. (2007). Market share (49%) from Energy Star 2006 appliance sales data.

Refrigerator Tier I
Measure Description: Replacement refrigerator that meets 2008 ENERGY STAR requirements (20% better than federal standard)

Basecase: Refrigerator that meets current 2001 federal energy standards.

Data Explanation: Baseline consumption, incremental cost ($64) and measure life (19 years) from ACEEE analysis for PG&E/CA Title 24 (PG&E 2007). Market share (31%) from Sanchez et al. (2007).

Refrigerator Tier II
Measure Description: Replacement refrigerator that exceeds federal energy standard by 25% (CEE Tier 2)

Basecase: Refrigerator that meets current 2001 federal energy standards.

Data Explanation: Baseline consumption, incremental cost ($33) and measure life (19 years) from ACEEE analysis for PG&E/CA Title 24 (PG&E 2007).

Horizontal-Axis Clothes Washer (appliances)
Measure Description: Front-loading (H-axis) clothes washer meeting ENERGY STAR requirements (2.0 MEF)

Basecase: Federal standard for clothes washers: 1.26 MEF

Data Explanation: Incremental cost ($30) and electricity savings (20%) from ENERGY STAR savings calculator, isolating appliance energy savings only. Incremental cost ($200) apportioned based on percentage of electricity consumption not dedicated to water heating. Percent of homes based on appliance saturation data from RECS 2005 (EIA 2008b). 2006 market share (33%) from EPA (2007). Measure life (14 years) is from Sanchez et al. (2007).

Horizontal-Axis Clothes Washer (water heating)
Measure Description: Front-loading (H-axis) clothes washer meeting ENERGY STAR requirements (2.0 MEF)

Basecase: Federal standard for clothes washers: 1.26 MEF

Data Explanation: Incremental cost ($270) and energy savings from ENERGY STAR savings calculator, isolating water heating energy savings only. Incremental cost ($200) apportioned based on percentage of electricity consumption dedicated to water heating. Percent of homes based on appliance saturation data from RECS 2005 (EIA 2008b). 2006 market share (33%) from EPA (2007). Measure life (14 years) is from Sanchez et al. (2007).

Efficient Dishwasher (appliances)
Measure Description: Dishwasher meeting 2007 CEE Tier 2 requirement, 0.68 EF

Basecase: Dishwasher meeting 2010 federal energy standard of 0.62 EF

Data Explanation: Incremental cost ($30) and electricity savings from DOE 2007 Technical Support Document, isolating appliance energy savings only. Incremental cost apportioned based off ratio of electricity savings between the appliance and electricity used for water heating. Measure life (13 years) is from Sanchez et al. (2007). Market share (15%) from April 2007 LBL analysis on the AHAM-efficiency advocate agreement.

Efficient Dishwasher (water heating)
Measure Description: Dishwasher meeting 2007 CEE Tier 2 requirement, 0.68 EF

Basecase: Dishwasher meeting 2010 federal energy standard of 0.62 EF

Data Explanation: Incremental cost ($30) and energy savings from DOE 2007 Technical Support Document, isolating water heating energy savings only. Incremental cost apportioned based off ratio of electricity savings between the appliance and electricity used for water heating. Measure life (13 years) is from Sanchez et al. (2007). Market share (15%) from April 2007 LBL analysis on the AHAM-efficiency advocate agreement.

Ceiling Fan
Measure Description: ENERGY STAR certified ceiling fan

Basecase: Standard ceiling fan as defined by ENERGY STAR

Data Explanation: Baseline consumption, new measure consumption, and incremental cost from ENERGY STAR calculator. 2.21 units per household assumed from RECS 2005 (EIA 2008b). Baseline and new measure consumption, as well as units per household, specific to South Atlantic region. Measure life (10 years) and market share (24%) are from Sanchez et al. (2007).

Compact Fluorescent Lighting
Measure Description: Savings from the 17-watt equivalent to baseline lamp (75%) applied to 80% of baseline incandescent lamp hours.

Basecase: Baseline house requires 25,659 incandescent lamp-hours per year; average incandescent wattage is 63 watts based on 2001 federal government lighting inventory survey (DOE 2002).

Data Explanation: Measure of 80% replacement by lamp-hours is ACEEE assumption based on a conservative estimate of feasible applications. Applies to all households. Market share (10%) from ACEEE estimate based on EPA's estimate of Energy Star lamp sales in 2007 and ACEEE's estimate of total lamp sales.

Active Mode Efficiency for Televisions
Measure Description: Active mode standard for televisions equivalent to ENERGY STAR Draft 2 specification

Basecase: Average of all TVs from ENERGY STAR data set that do not pass Draft 2 specification

Data Explanation: Baseline and new measure savings data are from Chase (2008) and are based on the data set that was used in the ENERGY STAR Draft 2 TV specification revision. Measure life from Appliance Magazine (September 2007). Market share data from 2007 Draft 2 Energy Star documents (www.energystar.gov). No reliable incremental cost data is available. The cost variance among a range of non-energy-related TV components is dramatically more significant to the consumer, resulting in very low cost per kWh saved per household. Our estimate is set to result in a levelized cost similar to that for the 1-watt standby measure.

Low Power Set-Top Boxes
Measure Description: Require digital set-top boxes to have a maximum sleep state power level of 10 watts and to automatically enter sleep mode after 4 hours without user input.

Basecase: Typical house with 1.9 set top boxes.

Data Explanation: All data except cost is from Rainer (2008). No reliable incremental cost data is available. In the case of set-top boxes, efficiency measures are largely software-related, likely resulting in very low cost per kWh saved per household. Our cost estimte is set to result in a levelized cost similar to that for TVs.

One-Watt Standby for All Household Electronics
Measure Description: All new electronics devices required to have maximum "off" mode power level of 1 watt.

Basecase: Typical house with 17-20 devices.

Data Explanation: Baseline consumption, savings, incremental costs and measure life available from ACEEE 2004 emerging technologies analysis (Sachs et al. 2004). Penetration of new measure assumed by averaging market shares of all ENERGY STAR home electronics equipment.

ENERGY STAR New Home
Measure Description: New home that uses 15% less energy than code

Basecase: Code-compliant home (proposed 2008 IECC residential code revision)

Data Explanation: Baseline equals delivered HVAC and water heating energy use per household (across all households) from AEO (2007). Incremental costs ($805) and market share (5%) from personal communication with Shadid (2007). Percent applicable for new homes assume that 30% and 50% new buildings are phased-in one to two years prior to enactment of codes (30% in 2012 and 50% in 2020).

Advanced Building Code New Home
Measure Description: New home that uses 30% less energy than code

Basecase: Code-compliant home (proposed 2008 IECC residential code revision)

Data Explanation: Baseline equals delivered HVAC and water heating energy use per household (across all households) from AEO (2007). Incremental costs ($1480) and market share (0%) from personal communication wtih Shadid (2007). Percent applicable for new homes assume that 30% and 50% new buildings are phased-in one to two years prior to enactment of codes (30% in 2012 and 50% in 2020).

Tax-Credit-Eligible New Home
Measure Description: New home that uses 50% less energy than code.

Basecase: Code-compliant home (proposed 2008 IECC residential code revision)

Data Explanation: Baseline equals delivered HVAC and water heating energy use per household (across all households) from AEO (2007). Incremental costs ($2775) and market share (0%) from personal communication wtih Shadid (2007). Percent applicable for new homes assume that 30% and 50% new buildings are phased-in one to two years prior to enactment of codes (30% in 2012 and 50% in 2020).

C.2.Commercial Buildings

C.2.1. Baseline End-Use Electricity Consumption

To estimate the resource potential for efficiency in commercial buildings in Virginia, we first develop a disaggregate characterization of baseline electricity consumption in the state for current electricity use and a reference load forecast (see Table C.1 below). Highly disaggregated commercial electricity consumption data is unfortunately not available at the state level. To estimate these data, we start with current electricity consumption for the Virginia commercial sector (EIA 2008) and a forecast out to 2025 based on PJM forecasts, and we disaggregate by end-use using average regional data from CBECS 2003 (EIA 2006b) and AEO 2007 (EIA 2007c).

Table C.1. Baseline Commercial Electricity Consumption by End-Use (GWh)

End-Use	2009	%	2015	%	2025	%
Heating	1,837	4%	2,141	4%	2,339	3%
Ventilation	5,792	12%	6,751	12%	7,902	12%
Cooling	2,463	5%	2,871	5%	3,292	5%
HVAC Subtotal	*10,092*	*21%*	*11,763*	*21%*	*13,534*	*20%*
Water Heating	1,293	3%	1,507	3%	1,592	2%
Refrigeration	2,979	6%	3,472	6%	3,959	6%
Lighting	16,945	35%	19,750	35%	22,717	33%
Office Equipment	6,970	14%	8,124	14%	10,810	16%
Appliances and Other	10,215	21%	11,905	21%	15,473	23%
Total	48,494	100%	56,522	100%	68,083	100%

Next, we estimate commercial square footage in the state using electricity intensity data (kWh per square foot) by census region from CBECS (EIA 2006b). We use an average of the South Atlantic (18.3 kWh/s.f.) and Mid Atlantic (12.5 kWh/s.f) census regions to estimate an overall electricity intensity for the state of Virginia of 15.4 kWh per square foot. Total electricity consumption in the state divided by the electricity intensity provides an estimate of commercial floorspace. Using this methodology, we estimate 3,149 million square feet of commercial floorspace in the state.

C.2.2. Measure Cost-Effectiveness

We then analyze 33 efficiency measures for existing commercial buildings and 3 new construction whole-building measures to examine the cost-effective energy efficiency resource potential. For each efficiency measure, we estimate electricity savings (*Annual Savings per Measure)* and incremental cost (*Measure Cost)* in a "replacement on burnout scenario," which assumes that the product is replaced or the measure is installed at the end of the measure's useful life. Savings and costs are incremental to an assumed *Baseline Measure*. We estimate savings (kWh) and costs ($) on a per-unit and/or a per-square foot commercial floorspace basis. For each measure we also assume a *Measure Lifetime*, or the estimated useful life of the product.

A measure is determined to be cost-effective if its levelized cost of saved energy, or cost of conserved energy (CCE), is less than 8.4 cents/kWh, the estimated current average commercial cost of electricity in Virginia. The estimated CCE for each efficiency measure, which assume a discount rate of 5%, are shown in the measure descriptions below. Equation 1 shows the calculation for cost of conserved energy.

Our assumed *Baseline Measure, Annual Savings per Measure, Measure Cost, Measure Lifetime, and CCE* are reported for each of the efficiency measures in the list of measure descriptions below. We group the 33 efficiency measures for existing commercial buildings by end-use and list the 3 new building measures last.

Equation 1. *CCE = PMT ((Discount Rate), (Measure Lifetime), (Measure Cost)) / (Annual Savings per Measure (kWh))*

C.2.3. Total Statewide Resource Potential

For each measure, we then derive *Annual Savings per Measure* on a per square foot basis *(kWh per square foot)* for the applicable end-use. For measures that we only have savings on a per-unit or per-building basis, we first derive the percent savings and multiply by the *Baseline Electricity Intensity* for that end-use. The assumed baseline intensities for each end use are shown in Table C.2. As an example, for a specific lighting measure we multiply its percent savings by the baseline electricity intensity (kWh per square foot) for the lighting end-use.

Table C.2. Commercial End-Use *Baseline Electricity Intensities* (kWh per s.f.)

End-Use	2009
Heating	0.6
Ventilation	1.8
Cooling	0.8
HVAC Subtotal	3.2
Water Heating	0.4
Refrigeration	0.95
Lighting	5.4
Office Equipment	2.2
Appliances and Other	3.2
Total	15.4

To estimate the total efficiency resource potential in existing commercial buildings in Virginia by 2025, we must first adjust the individual measure savings by an *Adjustment Factor* (See Equation 2). This factor accounts for two adjustments: the technical feasibility of efficiency measures, called the *Percent Applicable* (the percent of Virginia floorspace that satisfy the base case conditions and other technical prerequisites such as heating fuel type and cooling equipment, etc); and the *Current Market Share*, or the percent of products that already meet the efficiency criteria. These assumptions are outlined in each of the efficiency measure descriptions below.

Equation 2. *Adjustment Factor = Percent Applicable x (1-Current Market Share).*

We then adjust total savings for interactions among individual measures. For example, we must adjust HVAC equipment savings downward to account for savings already realized through improved building envelope measures (insulation and windows), which reduce heating and cooling loads. Similarly, we adjust water heating equipment savings to account for reduced water heating loads from the use of more efficient clothes washers. The multiplier for these adjustments is called the *Interaction Factor*.

Finally, we adjust replacement measures with lifetimes more than 7 and 17 years to only account for the percent turning over in 7 and 17 years, which represents the benchmark years of 2015 and 2025, respectively. Note that the multiplier, *Percent Turnover,* is only applicable to products being replaced upon burnout and not retrofit measures such as insulation. These retrofit measures therefore have 100% of measures "turning over."

We then calculate the resource potential for each measure in the state using Equation 3, which takes into account all of the adjustments described above. The sum of the resource potential from all measures is the overall energy efficiency resource potential in the state's commercial buildings sector.

Equation 3. *Efficiency Resource Potential in 2015 and 2025 (GWh) = (Annual Savings per Measure (kWh per square foot)) x (Commercial floor space in Virginia in millions of square feet) x (Percent Applicable)* x *(Interaction Factor) x (Percent Turnover)*

C.2.4. Efficiency Measures

Table C.3. shows the thirty-six efficiency measures examined for this analysis, grouped by end-use costs, savings (kWh) per product or square foot, *Percent Applicable, Interaction Factor, Percent Turnover,* and total savings potential (GWh) in 2025. Detailed descriptions of each measure are given below, grouped by end-use.

<u>**HVAC**</u>

1. Duct testing and sealing

Measure Description: Testing and sealing air distribution ducts saves energy. This measure assumes supply and return ducts will be fully sealed.

Basecase: The basecase assumes air loss of 29% of fan flow, and leakage of 15% of the system flow.

Data Explanation: 24,828 kWh savings per unit are for an average 21,721 ft^2 retail or education building. Percent savings of 6% apply to whole-building electricity consumption (SWEEP 2002). An incremental cost of $3,375, which assumes $300 per ton, a 10 year lifetime, and 25% applicability are ACEEE estimates. The levelized cost is calculated to be 1.8 cents/kWh.

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2. Cool roof

Measure Description: This measure involves installing a sun-reflective coating on the roof of a building with a flat top. This reduces air conditioning energy loads by reducing the solar energy absorbed by the roof.

Basecase: The baseline electricity intensity for HVAC end uses in Virginia (4.3 kWh/ft^2/year) is used as the basecase.

Data Explanation: We assume 4% HVAC load savings (ACEEE 1997) off the baseline electricity intensity for HVAC end-uses in MD (CBECS 2003), an incremental cost of $0.25 per ft^2 (SWEEP 2002), and a 20-year average lifetime (SWEEP 2002). Percent applicable (80%) is an ACEEE estimate. Savings and cost per unit are based on a 15,000 ft^2 building from ACEEE Mid-Atlantic study (1997). The levelized cost is calculated to be 5.5 cents/kWh.

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3. Roof insulation

Measure Description: Fiberglass or cellulose insulation material in roof cavities will reduce heat transfer, though the type of building construction limits insulation possibilities. R-values describe the performance factor for insulation levels.

Basecase: The basecase electricity intensity for this measure was disaggregated from the post-savings electricity intensity and the percentage of savings.

Data Explanation: We assume 3% savings and a post-savings electricity intensity of 0.28 kWh/ft^2/year, based on an average of four building types (ACEEE 1997). An average lifetime of 20 years and an incremental cost of 12 $cents/ft^2$ were also assumed.

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4. Double Pane Low-Emissivity Windows

Measure Description: Double-pane windows have insulating air- or gas-filled spaces between each pane, which resist heat flow. Low-emissivity (low-e) glass has a special surface coating to reduce heat transfer back through the window, and a window's R-value represents the amount of heat transfer back through a window.
Low-e windows are particularly useful in climates with heavy cooling loads, because they can reflect anywhere from 40% to 70% of the heat that is normally transmitted through clear glass. The Solar Heat Gain Coefficient (SHGC) represents the fraction of solar energy transferred through a window. For example, a low-e window with a 0.4 SHGC keeps out 60% of the sun's heat.

Basecase: The basecase electricity intensity for this measure was disaggregated from the post-savings electricity intensity and the percent savings.

Data Explanation: Percent savings of 3% apply to whole-building electricity consumption (ACEEE 1997). Incremental costs assume $2 per window (SWEEP 2002). A measure life of 25 years is from SWEEP 2002. Percent applicable is an ACEEE estimate. The levelized cost is calculated to be 3.4 cents/kWh.

5. Ventilation fans with Variable-Frequency Drive

Measure Description: Variable Frequency Drive (VFD) controls the speed of a motor by adjusting the frequency of incoming power. By controlling the speed of a motor, the output of the system can be matched to the requirements of the process, thereby improving efficiency.

Basecase: The basecase unit is a 50 hp fan with 60% load factor, 93% efficiency (ODP, EPAct levels) and 3653 operating hours/year (21-50 hp category from ACEEE standards savings analysis).

Data Explanation: We assume 25% savings applies to ventilation only (ACEEE 1997), which is a conservative estimate. We estimate a $6,650 incremental cost, which assumes $125/hp for VFD and $8/hp for a better fan, and a 10-year measure life (SWEEP 2002). ACEEE estimates that this measure can apply to 40% of systems. The levelized cost is calculated to be 3.9 cents/kWh.

6. High-Efficiency Unitary AC/HP
65,000 Btu — 135 Btu
135,000 Btu — 240,000 Btu

Measure Description: Unitary packaged air conditioners and heat pumps represent the heating, ventilating, and air conditioning (HVAC) equipment class with the greatest energy use in the commercial sector in the United States, and are used in approximately 48 percent of the cooled floor space in the commercial sector (DOE 2004). High efficiency units have a greater energy efficiency ratio (EER).

Basecase: The assumed basecase unit meets the 2010 federal efficiency standard. Baseline electricity intensity for this end-use, 3 kWh per ft^2, is the estimated HVAC consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA's commercial buildings survey (EIA 2006b).

Data Explanation: This measure includes two size ranges; the first is 65,000 Btu to 135,000 Btu, and the second is 135,000 btu to 240,000 Btu. The measure assumes a 12 EER unit relative to the 2010 federal standard, which ranges from about 10.4 EER to 11.2 EER, depending on the unit type and size. The energy savings average 1,070 kWh (7.2%) for the smaller unit and 3,371 kWh (10.8%) for the larger unit. We assume a measure lifetime of 15 years (LBNL 2003). Incremental costs (average $629 for 65 kBtu to135 kBtu and $1,415 for 135 kBtu to 240 kBtu) are derived from DOE's Technical Support Document (DOE 2004). Percent applicable (33% for 65 kBtu to135 kBtu), and the percent of floorspace with cooling from unitary equipment are also from DOE's Technical Support Document (DOE 2004). The levelized cost is calculated to be 4–5.7 cents/kWh, depending on unit type and size.

7. High-Efficiency Packaged Terminal AC/HP

Measure Description: PTACs and PTHPs are self-contained heating and air-conditioning units encased inside a sleeve specifically designed to go through the exterior building wall. The basic design of a PTAC is comprised of a compressor, an evaporator, a condenser, a fan, and an enclosure. They are primarily used to provide space conditioning for commercial facilities such as hotels, hospitals, apartments, dormitories, schools, and offices.

High-efficiency units have a higher energy efficiency ratio (EER) for cooling units and coefficient of performance (COP) for heat pumps.

Basecase: Consistent with all HVAC-related measures, the baseline electricity intensity is 3 kWh per ft^2, which is the estimated HVAC consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA's commercial buildings survey (EIA 2006b).

Data Explanation: We assume that high efficiency units save an average of 7.8%, or 226 kWh per unit, relative to a basecase, which is based on an ACEEE submission to ASHRAE using web data. The measure life is 15 years (ASHRAE 90.1-1999). Percent applicable is 5%, which is the percent of cooling floorspace from packaged terminal units (ADL 2001). The levelized cost is calculated to be 3.8 cents/kWh.

8. Efficient Room Air Conditioner

Measure Description: An Energy Star room AC must be at least a 10% improvement over the 2000 federal standard (an average 8000 Btu unit must have a 10.8 EER).

Basecase: The assumed basecase unit is a room A/C that meets 2000 federal energy standards (an average 8000 Btu unit has a 9.8 EER) and uses an average of 1212 kWh per unit. Baseline electricity intensity for this end-use, 2.5 kWh per ft^2, is the estimated cooling consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA's commercial buildings survey (EIA 2006).

Data Explanation: We assume an Energy Star room AC uses 1100 kWh per year, saves 9% of basecase energy, and has an incremental cost of $30 (Energy Star calculator). The percentage of homes applicable (8%) is based on saturation data, and the number of units per home is from RECS 2005 (EIA 2008b). We assume a measure life of 9 years (Energy Star calculator), a current market share of 52% (EPA 2007), and percent applicable assumes 4% percent of cooling floorspace uses room AC units (ADL 2001). The levelized cost is calculated to be 3.8 cents/kWh.

9. High-Efficiency Chiller

Measure Description: "Chillers" are the hearts of very large air-conditioning systems for buildings and campuses with central chilled water systems. A centrifugal chiller utilizes the vapor compression cycle to chill water and reject the heat collected from the chilled water plus the heat from the compressor to a second water loop controlled by a cooling tower.

Basecase: The basecase unit assumes 0.634 kW/ton T24 from DEER for an average 150 ton system and 1,593 national average full-load operating hours from the ASHRAE 90.1-1999 analysis. Baseline electricity intensity for this end-use, 3.2 kWh per ft^2, is the estimated HVAC consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA's commercial buildings survey (EIA 2006b).

Data Explanation: We assume the new measure has 20% savings, which is derived from estimates provided in SWEEP 2002 and ACEEE 1997. The lifetime estimate of 23 years is from the ASHRAE Handbook (HVAC Applications). Incremental costs are $9,900 and assume a 150 ton average unit (CEC 2005). Percent applicable (33%) assumes percentage of cooling floorspace using chillers (ADL 2001). The levelized cost is calculated to be 2.4 cents/kWh.

10. Dual-Enthalpy Economizer

Measure Description: Economizers modulate the amount of outside air introduced into the ventilation system based on the relative temperature and humidity of the outside and return air. If the enthalpy, or the latent and sensible heat, of the outside air is less than that of the return air when space cooling is required, then the outside air is allowed to reduce or eliminate the cooling requirement of the AC equipment.

Basecase: Baseline electricity intensity, 3 kWh per ft^2, is the estimated HVAC consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA's commercial buildings survey (EIA 2006b).

Data Explanation: Savings per unit assume 276 kWh (20% savings) per ton for an average 11-ton unit (CL&P 2007). Average measure life is 10 years (CL&P 2007). Incremental costs per unit are from NYSERDA 2003.

Percent applicable is the portion of cooling square footage represented by packaged AC and HP units, and assumes that 90% of these unitary systems could benefit from economizers (ACEEE estimate). It also assumes a 5% current market share (ACEEE estimate). The levelized cost is calculated to be 3.8 cents/kWh.

11. HVAC Tune-up

Measure Description: Most HVAC technicians lack interest, training, equipment and methods to perform quality refrigerant charge and airflow (RCA) tune-ups. Because many new and existing air conditioners have improper RCA, which reduces efficiency, there is significant potential for energy savings by diagnosing and correcting RCA.

Basecase: The assumed basecase unit is a 4.5 ton commercial unitary AC/HP per California program experience (CPUC 2006), estimated to use 8,396 annual kWh per the unitary AC/HP measure. The base electricity intensity for the HVAC end-use is 3 kWh/ ft^2, the average for small buildings less than 25,000 ft^2, for which this measure is applicable.

Data Explanation: We assume 11% percent savings from this measure according to California's DEER database (CEC 2005) and the California Refrigerant and Air Charge (RCA) program report (CPUC 2006). We assume that 60% of units have improper RCA (CPUC 2006), and therefore this measure is applicable to 60% of unitary HVAC units in buildings less than or equal to 25,000 ft^2 (CBECS 2003; average of south and mid-Atlantic regions). We estimate an average measure life of 3 years, as units need to be periodically re-tuned. We assume a cost of $158 for this measure, based on a $35/ton labor cost (CEC 2005) and an assumed 4.5-ton unit. The levelized cost is calculated to be 6.3 cents/kWh.

12. Energy Management System (EMS)

Measure Description: An Energy Management System (EMS) is a computerized system that collects, analyzes and displays information on HVAC, lighting, refrigeration, and other commercial building subsystems to aid commercial building and facility energy managers, financial managers, and electric utilities in reducing energy use in buildings.

Basecase: Baseline electricity intensity is the average HVAC end-use consumption in Virginia, estimated from CBECS (EIA 2006b) to be the average of consumption in the Mid- and South-Atlantic regions.

Data Explanation: We assume 10% cooling savings and 7.5% heating and ventilation savings from an installed EMS (NYSERDA 2003). We estimate a 15-year measure life for the system. We assume total incremental costs of $19,333 for a 60,000 ft^2 building, which is derived from NYSERDA 2003, and assume a third of this ($6,380) for this measure by assuming the cost is spread equally among electric HVAC, gas HVAC and lighting. Percent applicable is an ACEEE estimate. The levelized cost is calculated to be 3.6 cents/kWh.

13. Retrocommissioning

Measure Description: Commercial building performance tends to degrade over time, and many new buildings do not perform as designed, requiring periodic upgrades to restore system functions to optimal performance. Retrocommissioning (RCx) is a systematic process to optimize building performance through O&M tune-up activities and diagnostic testing to identify problems in mechanical systems, controls, and lighting. The best candidates for RCx are buildings over 50,000 or 100,000 ft^2.

Basecase: The baseline is electricity intensity for HVAC and lighting end-uses in buildings greater than 50,000 ft^2 (10 kWh/ ft^2), which is based on data from CBECS (EIA 2006b). We take the average of the Mid-Atlantic and South Atlantic regions to estimate electricity intensity in Virginia buildings.

Data Explanation: We assume 10% savings for HVAC and lighting end-uses (Sachs et al. 2004) in all commercial floorspace for buildings greater than 100,000 ft^2, and 50% of floorspace in buildings 50,000 ft^2 or greater based on data from CBECS (EIA 2006b). Xcel Energy's RCx program results estimate an average RCx useful life of 7 years (Xcel Energy 2006). We assume a $0.25 cost per ft^2 (Sachs et al. 2004). The levelized cost is calculated to be 4.3 cents/kWh.

14. Demand-Controlled Ventilation

Measure Description: Often, HVAC systems are designed to supply ventilated air based on assumed occupancy levels, resulting in over-ventilation. Demand-controlled ventilation monitors CO_2 levels in different zones and delivers the required ventilation only when and where it is needed.

Basecase: The basecase is standard ventilation electricity consumption for a 50,000 ft^2 office building, or about 40,000 kWh/year (Sachs et al. 2004). Baseline electricity intensity for this end-use, 0.8 kWh per ft^2, is the estimated ventilation consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA's commercial buildings survey (EIA 2006b).

Data Explanation: We assume 20% savings for this measure (ET 2004). Energy use per unit is 32,000 kWh/year, assuming a 50,000 ft^2 building (Sachs et al. 2004). The lifetime estimate is 15 years, and incremental costs are $3,450 (Sachs et al. 2004). The measure is applicable to 90% of larger (60%) cooling units (Sachs et al. 2004). The levelized cost is calculated to be 4.2 cents/kWh.

Water Heating Measures

15. Heat Pump Water Heater

Measure Description: A heat pump water heater uses electricity to move heat from one place to another, rather than a less efficient electric resistance water heater which uses electricity to generate the heat directly. The heat source is the outside air or air in the basement where the unit is located.

Basecase: The basecase is standard electric water heating, with electricity consumption of 22,831 kWh/year (derived from energy savings and percent savings). Baseline electricity intensity for this end-use, 0.41 kWh per ft^2, is the estimated water heating consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA's commercial buildings survey.

Data Explanation: We assumed a 62% savings, based on a simple coefficient of performance ratio. The assumed 14,155 kWh savings, $4,067 incremental cost, and 12 year lifetime estimates are from NYSERDA 2003. Percent applicable is based on engineering estimates for NYSERDA 2003, which assumes the measure is applicable to 70% of food service floorspace and 30% of lodging, education, and health care floorspace. Percent applicable is then multiplied by 2, since these building types are more energy and hot-water intensive than the average commercial building. The levelized cost is calculated to be 3.2 cents/kWh.

16. Efficient Commercial Clothes Washer (water heating portion)

Measure Description: A high-efficiency commercial clothes washer saves both energy and water, and as a result reduces water heating loads. For a high-efficiency clothes washer, we assume a unit with an MEF of 2.0, which represents about 80% of products on Energy Star's product lists.

Basecase: The basecase unit is a clothes washer that meets DOE's federal efficiency standard of 1.26 MEF. An average unit consumes 1,136 kWh annually for water heating, which is derived from DOE 2007. Baseline electricity intensity for this end-use is 0.55 kWh/ft^2/year (water heating portion only).

Data Explanation: Savings on electric water heating from this measure assume a 2.0 MEF clothes washer uses an average 431 kWh annually, for a 62% savings, which is derived from DOE's TSD (DOE 2007). We assume the measure is applicable to the 17% of units that have electric water heating, and assume a 20% market share of efficient products. The overall stock estimate is based on national stock data (DOE 2007) and prorated to Virginia based on commercial building floorspace. We assume an incremental cost for an efficient unit is $316 and an 11-year measure life (DOE 2007). The levelized cost is calculated to be 3.7 cents/kWh.

Refrigeration Measures

17. Efficient Walk-In Refrigerators & Freezers

Measure Description: Walk-in refrigerators and freezers (walk-ins) are medium and low-temperature refrigerated spaces that can be walked into, and that are used to maintain the temperature of pre-cooled materials (not to rapidly cool down materials from warmer temperatures). A high-efficiency walk-in is defined as meeting the 2004

CEC standard for walk-ins. This includes prescriptive requirements such as higher levels of insulation, motor types, and the use of automatic door-closers (Nadel et al. 2006).

Basecase: The baseline energy use for an average walk-in is 18,859 kWh/year (Nadel et al. 2006). Baseline electricity intensity for this end-use, 0.95 kWh per ft^2, is the estimated refrigeration energy consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA's commercial buildings survey.

Data Explanation: For a high-efficiency walk-in unit, we assume 44% savings over a baseline unit, or 8220 kWh/year, $957 incremental cost, and a 12 year measure lifetime (Nadel et al. 2006), which are based on a PG&E CASE study (2005). We estimate percent applicable as the 18% of refrigeration energy use attributed to walk-ins (ADL 2006) and estimate a 50% current market share of high-efficiency products (ACEEE estimate). The levelized cost is calculated to be 1.3 cents/kWh.

18. Efficient Reach-In Coolers & Freezers

Measure Description: This measure includes high-efficiency packaged commercial reach-in refrigerators and freezers with solid doors, and refrigerators with transparent doors such as beverage merchandisers. High-efficiency units are those that meet the CEE Tier 2 performance standard, as estimated in PG&E 2005.

Basecase: We assume a baseline unit, which is one that meets that upcoming (2009 or 2010) federal standard, uses 4,027 kWh per year. This is weighted by sales of unit type per PG&E 2004. Baseline electricity intensity for this end-use, 0.95 kWh per ft^2, is the estimated refrigeration energy consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA's commercial buildings survey.

Data Explanation: The savings estimate for a high-efficiency unit, 31% savings or 1,268 kWh per year, is a weighted average of different types of reach-ins that meet CEE's Tier 2 performance standard (PG&E 2005). We estimate an average lifetime of 9 years and an incremental cost of $341, both per PG&E 2005. We estimate percent applicable as the percent of refrigeration energy use attributed to reach-ins and beverage merchandisers, or 17% (ADL 2006), and assume a 10% current market share of high-efficiency products per PG&E 2005. The levelized cost is calculated to be 2.2 cents/kWh.

19. Efficient Ice-Maker

Measure Description: Commercial ice makers, which are used in hospitals, hotels, and food service and preservation, have energy savings potential largely in their refrigeration systems. We assume an efficient icemaker meets CEC's Tier 2 level of energy savings, which incorporate improved compressors, heat exchangers, and controls, as well as better insulation and gaskets.

Basecase: The baseline energy use, 3,338 kWh per year, is a weighted average of different types of ice-makers that meet the 2010 standard. Baseline electricity intensity for this end-use, 0.95 kWh per ft^2, is the estimated refrigeration energy consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA's commercial buildings survey.

Data Explanation: The 16% savings estimate for a high-efficiency unit, or 542 kWh per year, is a weighted average of different types of ice-makers that meet CEC's tier 2 energy savings (PG&E 2005). We estimate an average lifetime of 10 years and an incremental cost of $100, both per PG&E 2005. We estimate percent applicable as the percent of refrigeration energy use attributed to ice-makers, or 10% (ADL 2006), and assume a 10% current market share of high-efficiency products per PG&E 2005 and ACEEE judgment. The levelized cost is calculated to be 2.4 cents/kWh.

20. Efficient Built-up Refrigeration System

Measure Description: Built-up or supermarket refrigeration systems are primarily made up of refrigerated display cases for holding food for self-service shopping, as well as machine room cooling technologies. More efficient built-up systems include improved machine room technologies (evaporative condensers, mechanical sub-cooling, and heat reclaim), high-efficiency evaporative fan motors, hot gas defrost, liquid-suction heat exchangers, antisweat control, and defrost control.

Basecase: The measure baseline is 1,600,000 kWh for a 45,000 ft^2 supermarket with a built-up refrigeration system. Baseline electricity intensity for this end-use, 0.95 kWh per ft^2, is the estimated refrigeration energy consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA's commercial buildings survey.

Data Explanation: Per-unit savings of 336,000 kWh (21%) are from ADL 1996 and assume an average new 45,000 ft^2 supermarket with a 5-year payback. We estimate percent applicable as the percent of refrigeration energy use attributed to built-up refrigeration, or 33% (ADL 1996). Incremental cost ($37,000) and lifetime (10 years) are from ADL 1996. The levelized cost is calculated to be 1.3 cents/kWh.

21. Efficient Vending Machine

Measure Description: Energy Star vending machines must consume 50% less energy than standard machines. Under the Tier II ENERGY STAR level, this translates to a maximum energy consumption of 6.53 kWh/day for a 650-can machine.

Basecase: A Tier I ENERGY STAR level vending machine is assumed to be the basecase. On average, it uses 2,816 kWh per year (Energy Star calculator for a 600 can machine). Baseline electricity intensity for this end-use, 0.95 kWh per ft^2, is the estimated refrigeration energy consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA's commercial buildings survey.

Data Explanation: Per unit savings of 18% (509 kWh/year) are estimated from ASAP 2007 based on Energy Star calculator estimates. Likewise, an incremental cost of $30, and a lifetime estimate of 10 years are from ASAP 2007. We estimate percent applicable as the percent of refrigeration energy use attributed to built-up refrigeration, or 13% (NYSERDA 2003). Stock estimates are from the 2005 TSD (DOE 2005). The levelized cost is calculated to be 0.8 cents/kWh.

22. Vending Miser

Measure Description: A Vending Miser is an energy control device for refrigerated vending machines. Using an occupancy sensor, the control turns off the machine's lights and duty cycles the compressor based on ambient air temperature.

Basecase: The basecase unit is an efficient vending machine that meets the Energy Star tier II level and uses 2,309 kWh per year (Energy Star calculator for a 600 can machine). Baseline electricity intensity is for the refrigeration end-use (0.95 kWh/ ft^2).

Data Explanation: We assume 35% savings for this measure based on manufacturer data (usatech.com 2008), an incremental cost of $167 (NYSERDA 2003), and a measure life of 10 years (NYSERDA 2003). The levelized cost is calculated to be 2.7 cents/kWh.

23. Efficient Hot Food Holding Cabinets

Measure Description: Commercial hot food holding cabinets are used in the commercial kitchen industry primarily for keeping food at safe serving temperature, without drying it out or further cooking it. These cabinets can also be used to keep plates warm and to transport food for catering events. High efficiency models differ mainly in that they are better insulated.

Basecase: The basecase unit is an uninsulated cabinet that consumes 5,190 kWh per year. This was calculated from CASE (2004) using a simple average of three sizes of cabinets, and then weighting the average using CASE figures for insulated cabinets.

Data Explanation: The energy savings from an insulated holding cabinet are 1,815 kWh per year (35% savings), with an incremental cost of $453, and an estimated 15 year lifetime (ASAP 2007, based on PG&E CASE study (2004)). Percent applicable refers to the 25% of holding cabinets that are currently uninsulated (ASAP 2007, based on PG&E CASE study (2004)). The levelized cost is calculated to be 2.4 cents/kWh.

24. Efficient Commercial Clothes Washer (excluding hot water energy)

Measure Description: A high-efficiency commercial clothes washer saves both energy and water. For a high-efficiency clothes washer, we assume a unit with an MEF of 2.0, which represent about 80% of products on Energy Star's product lists.

Basecase: The basecase unit is a clothes washer that meets DOE's federal efficiency standard of 1.26 MEF. An average unit consumes 1,530 kWh annually for non-water heating uses, which is derived from DOE 2007.

Data Explanation: Electric savings from this measure assume a 2.0 MEF clothes washer uses an average 1,191 kWh annually, for a 22% savings, which is derived from DOE's TSD (DOE 2007). We assume the measure is applicable to the 39% of units that have electric dryer heating (removal of moisture from clothes), and assume a 20% market share of efficient products. The overall stock estimate is based on national stock data (DOE 2007) and prorated to Virginia based on commercial building floorspace. We assume an incremental cost for an efficient unit is $316 and an 11-year measure life (DOE 2007). The levelized cost is calculated to be 3.7 cents/kWh.

Lighting Measures

25. Fluorescent Lighting Improvements

Measure Description: The new measure assumes extra-efficient ballasts and high-lumen lamps are installed with no change in light level (low ballast factor).

Basecase: Basecase watts per square foot reflect current installed fixtures. This includes 84,000 annual tube fluorescent kWh used per average 14,000 ft^2 commercial building (Navigant 2002). On average, fluorescent lights are operated 9.7 hours/day. We assume 2-lamp standard T8 fixtures and electronic ballasts as the baseline, plus a small number of existing 3-lamp T12 fixtures with magnetic ballasts that are not likely to be replaced in the absence of programs over the time horizon.

Data Explanation: We assume a percent savings of 27%.The incremental costs are $2 extra per ballast, and $1 extra for each of 2 lamps. The percent applicable (56%) is the fluorescent percent of total commercial lighting kWh (Navigant 2002). The levelized cost is calculated to be 0.6 cents/kWh.

26. HID Lighting Improvements

Measure Description: Metal halide lamps produce light by passing an electric arc through a mixture of gases. Efficiency improvements in metal halide lamps include pulse start lamp technology, electronic ballasts, and improved fixtures.

Basecase: Same basecase as #27 (Fluorescent lighting improvements).

Data Explanation: The new measure savings and costs are from a PG&E CASE study on Metal Halide Lamps & Fixtures (PG&E 2004). Energy savings were 447 kWh per year (26%), and incremental costs were $60. Percent applicable (12%) is the percentage of commercial electricity use for lighting that comes from HIDs (Navigant 2002). The levelized cost is calculated to be 6.3 cents/kWh.

27. Replace Incandescent Lamps

Measure Description: The new measure assumes that 4 average 75 W incandescent lamps are replaced with 23 W CFLs. It is assumed that the lights operate 9.5 hours per day.

Basecase: Same basecase as #27 (Fluorescent lighting improvements).

Data Explanation: Energy savings are 180 kWh per year, or 69%. Incremental costs include $10 in the cost of 4 CFLs, but save $32 in labor for replacing the bulbs, so the result is a cost savings. Percent applicable assumes that 32% of commercial electricity use for lighting is from incandescents (Navigant 2002), and ACEEE estimates that 70% of sockets are applicable for the new measure. The levelized cost is calculated to be -1.3 cents/kWh.

28. Occupancy Sensor for Lighting

Measure Description: Installation of occupancy sensors can greatly reduce lighting energy demands in commercial spaces, by automatically turning off lights in unoccupied spaces.

Basecase: Same basecase as #27 (Fluorescent lighting improvements).

Data Explanation: Energy savings of 361 kWh per year (NYSERDA 2003) assumes 30% energy reduction in individual offices and rooms and 7.5% reduction in open spaces (ACEEE estimate). Incremental cost ($48) and lifetime (10 years) estimates are from NYSERDA 2003. Percent applicable (38%) is from ACEEE 2004. The levelized cost is calculated to be 1.7 cents/kWh.

29. Daylight Dimming System

Measure Description: A daylight dimming system automatically dims electric lights to take advantage (or "harvest") natural daylight.

Basecase: Same basecase as #27 (Fluorescent lighting improvements).

Data Explanation: Energy savings are estimated to be 143 kWh per year, or 35% (NYSERDA 2003). Savings apply for lamps on the perimeters of buildings (25% applicable—PIER 2003). Incremental cost ($68) and lifetime (20 years) estimates are from NYSERDA (2003). The levelized cost is calculated to be 3.8 cents/kWh.

30. Outdoor Lighting—Controls

Measure Description: This measure includes a variety of lighting control technologies for exterior lights.

Basecase: No basecase data was available for this measure.

Data Explanation: We assume a savings of 174 kWh, or 20%, from lighting controls. Incremental costs of $43 are from DEER 2001 and assume each control on average controls three fixtures. Percent applicable of 30% is an ACEEE estimate. The levelized cost is calculated to be 2.5 cents/kWh.

31. Office Equipment

Measure Description: This measure assumes a high-efficiency fax, printer, computer display, internal power supply, and a low mass copier.

Basecase: Baseline electricity use is 2886 kWh per year (NYSERDA 2003). Baseline electricity intensity for this end-use, 2.2 kWh per ft^2, is the estimated office equipment energy consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA's commercial buildings survey.

Data Explanation: Energy savings were 1410 kWh per year (49%), lifetime was 5 years, and incremental costs were $20. Percent applicable is estimated to be (50%) (NYSERDA 2003). The levelized cost is calculated to be 0.3 cents/kWh.

32. Efficient New Building (15% Savings)

Measure Description: Incorporating energy efficiency into building design is best achieved at the time of construction. New buildings can achieve major energy savings in heating and cooling, as well as energy-saving appliances.

Basecase: Basecase of 9.8 kWh per ft^2 is an estimate of HVAC, water heating, and lighting end-use electricity intensity for new buildings in Virginia, derived from data for buildings built from 2000-2003 (EIA 2006b).

Data Explanation: Incremental cost of $0.35 per ft^2 and measure life of 17 years are from NGRID 2007. Percent applicable of 18% for this new buildings measure assume that 30% and 50% new buildings savings are phased in one to two years prior to enactment of codes in the policy scenarios (30% in 2012 and 50% in 2020). The levelized cost is calculated to be 2.1 cents/kWh.

33. Efficient New Building (30% Savings)

Measure Description: Incorporating energy efficiency into building design is best achieved at the time of construction. New buildings can achieve major energy savings in heating and cooling, as well as energy-saving appliances.

Basecase: Basecase of 9.8 kWh per ft^2 is an estimate of HVAC, water heating, and lighting end-use electricity intensity for new VA buildings, derived from data for buildings built from 2000-2003 (EIA 2006b).

Data Explanation: In New York, estimates show that commercial buildings can reach 30% beyond code at an investment of \$0.54/kWh. To be conservative, we estimate \$0.70/kWh by doubling the costs of a 15%-beyond-code building. Measure life of 17 years is from NGRID 2007. Percent applicable of 35% for 30% savings new buildings assume that 30% and 50% new buildings savings are phased in one to two years prior to enactment of codes in the policy scenarios (30% in 2012 and 50% in 2020). The levelized cost is calculated to be 2.1 cents/kWh.

34. Tax-Credit Eligible Building (50% Savings)

Measure Description: A federal tax incentive is available for new buildings that are constructed to save at least 50% of the heating, cooling, ventilation, water heating, and interior lighting cost of a building that meets ASHRAE standard 90.1-2001.

Basecase: Basecase of 9.8 kWh per ft^2 is an estimate of HVAC, water heating, and lighting end-use electricity intensity for new buildings in Virginia, derived from data for buildings built from 2000-2003 (EIA 2006b).

Data Explanation: Incremental costs of \$3.00 per ft^2 are from ACEEE 2004. Measure life of 17 years is from NGRID 2007. The levelized cost is calculated to be 5.4 cents/kWh.

Table C.3. Commercial Energy Efficiency Measure Characterizations

Measures	End-Use	Measure Life (Years)	Annual kWh svgs per unit	2007 Virginia Stock	kWh svgs per s.f.	Incremental cost per unit	Incremental cost per s.f.	Cost of Conserved Energy (2006$/kWh saved)	Adjustment Factor	% Turnover	Interaction Factor	Savings in 2025 (GWh)
Existing Buildings												
HVAC												
Duct testing and sealing	HVAC	10	24,828	NA	0.53	$ 3,375	NA	$ 0.02	25%	100%	100%	352
Cool roof	HVAC	20	5,513	NA	0.16	$ 3,750	$ 0.25	$ 0.05	80%	85%	100%	289
Roof insulation	HVAC	20	NA	NA	0.28	NA	$ 0.12	$ 0.03	35%	100%	100%	257
Low-e windows	HVAC	25	NA	NA	0.26	NA	$ 0.07	$ 0.02	75%	68%	100%	358
Efficient ventilation fans & motors w VFD	HVAC	10	21,977	NA	0.26	$ 6,650	NA	$ 0.04	40%	100%	89%	249
Load-Reducing Measures Subtotal												**1,505**
High-effic. unitary AC & HP (65-135 kbtu)	HVAC	15	1,070	NA	0.31	$ 629	NA	$ 0.06	33%	100%	87%	237
High-effic. unitary AC & HP (135-240 kbtu)	HVAC	15	3,371	NA	0.47	$ 1,415	NA	$ 0.04	15%	100%	87%	161
Packaged Terminal HP and AC	HVAC	15	226	NA	0.34	$ 88	NA	$ 0.04	5%	100%	87%	39
Efficient room air conditioner	HVAC	9	112	NA	0.23	$ 30	NA	$ 0.04	4%	100%	87%	20
High-efficiency chiller system	HVAC	23	30,347	NA	0.87	$ 9,900	NA	$ 0.02	33%	74%	87%	487
HVAC Equipment Measures Subtotal	HVAC											**943**
Dual Enthalpy Control	HVAC	10	3,036	NA	0.51	$ 889	NA	$ 0.04	46%	100%	79%	480
Demand-Controlled Ventilation		15	8,000	NA	0.21	$ 3,450	NA	$ 0.04	54%	100%	79%	238
HVAC tuneup (smaller buildings)	HVAC	3	924	NA	0.37	$ 158	NA	$ 0.06	22%	100%	79%	172
Energy management system install	HVAC	15	23,200	NA	0.39	$ 6,380	NA	$ 0.03	33%	100%	79%	266
Retrocommissioning	HVAC	7	NA	NA	0.42	NA	$ 0.25	$ 0.04	43%	100%	79%	382
HVAC Control Measures Subtotal	HVAC											**1,536**
HVAC Subtotal												**3,986**
Water Heating												
Commercial clothes washers - 2.0 MEF	Water Heating	11	705	81,208	0.00	$ 316	NA	$ 0.04	14%	100%	100%	8
Heat pump water heater	Water Heating	12	14,155	NA	0.34	$ 4,067	NA	$ 0.03	24%	100%	99%	220
												228
Refrigeration												
Walk-in coolers & freezers	Refrigeration	12	8,220		0.56	$ 957	NA	$ 0.01	9%	100%	100%	134
Reach-in coolers & freezers	Refrigeration	9	1,268		0.40	$ 177	NA	$ 0.02	15%	100%	100%	165
Ice-makers	Refrigeration	10	542		0.21	$ 100	NA	$ 0.02	9%	100%	100%	51
Supermarket (built-up) refrigeration system	Refrigeration	10	336,000		0.27	$ 37,000	NA	$ 0.01	33%	100%	100%	233
Vending machines (to tier 2 Energy Star level)	Refrigeration	10	507		0.23	$ 30	NA	$ 0.01	13%	100%	100%	82

Measures	End-Use	Measure Life (Years)	Annual kWh svgs per unit	2007 Virginia Stock	kWh svgs per s.f.	Incremental cost per unit	Incremental cost per s.f.	Cost of Conserved Energy (2006$/kWh saved)	Adjustment Factor	% Turnover	Interaction Factor	Savings in 2025 (GWh)
Vending miser	Refrigeration	10	808		0.37	$ 167	NA	$ 0.03	13%	100%	100%	131
												796
Lighting												
Fluorescent lighting improvements	Lighting	14	64	NA	1.99	$ 4	NA	$ 0.01	56%	100%	100%	2,947
HID lighting improvements	Lighting	2	447	NA	1.90	$ 60	NA	$ 0.06	12%	100%	100%	603
Replace incandescent lamps	Lighting	13	180	NA	5.04	$ (22)	NA	$ (0.01)	22%	100%	100%	2,990
Occupancy sensor for lighting	Lighting	10	361	NA	1.36	$ 48	NA	$ 0.02	38%	100%	66%	915
Daylight dimming system	Lighting	20	143	NA	2.54	$ 68	NA	$ 0.04	25%	85%	61%	878
Retrocommissioning	Lighting	7	NA	NA	0.71	NA	$ 0.25	$ 0.04	43%	100%	57%	459
Outdoor lighting -- controls	Lighting	14	174	2,218,811	NA	$ 43	NA	$ 0.03	30%	100%	74%	86
												8,878
Office Equipment												
Office equipment	Office Equip.	5	1,410	-	1.46	$ 0.02	$ 20	$ 0.003	50%	100%	100%	1,935
												1,935
Appliances/Other												
Hot Food Holding Cabinets	Appliances	15	1,815	10,515	NA	$ 453	NA	$ 0.02	25%	100%	100%	5
Commercial clothes washers - 2.0 MEF	Appliances	11	339	81,208	NA	$ 316	NA	$ 0.04	31%	100%	100%	9
												13
Existing Buildings Subtotal												**15,837**
New Buildings												
Efficient new building (15% savings)	ALL	17	NA	NA	1.99	NA	$ 0.35	$ 0.02	18%	100%	100%	241
Efficient new building (30% savings)	ALL	17	NA	NA	3.98	NA	$ 0.70	$ 0.02	35%	100%	100%	964
Tax credit eligible building (50% svgs)	ALL	17	NA	NA	6.64	NA	$ 3.00	$ 0.04	47%	100%	100%	2,143
												3,348
											TOTAL	**19,185**

C.3. Industrial Sector

C.3.1. Overview of Approach

The analysis of electricity savings potential was accomplished in several steps. First, the industrial market in Virginia was characterized at a disaggregated level and electricity consumption for key end-uses was estimated. Then cost effective energy-saving measures were selected based on the projected average retail industrial electricity price. The economic potential savings for these measures was estimated by applying the efficiency measures to electricity end-use consumption. The following sections described the process for estimating the savings potential in Virginia.

C.3.2. Market Characterization and Estimation of Base Year Electricity Consumption

The industrial sector is made up of a diverse group of economic entities spanning agriculture, mining, construction and manufacturing. Significant diversity exists within most of these industry sub-sectors, with the greatest diversity within manufacturing. The various product categories within manufacturing are classified using the North American Industrial Classification System (NAICS) (Census 2002).[4]

Comprehensive, highly-disaggregated electricity data for the industrial sector is not available at the state level. To estimate the electricity consumption, this study drew upon a number of resources, all using the NAICS system and a consistent sample methodology. Fortunately, a conjunction of the various economic censuses for each state allows us to use a common base-year of 2002.

We then used national industry electricity intensities derived from industry group electricity consumption data reported in the *2002 Manufacturing Energy Consumption Survey* (MECS) (EIA 2005) and value of shipments data reported in the *2002 Annual Survey of Manufacturing* (ASM) (Census 2005) to apportion industrial electricity consumption. These intensities were then applied to the value of shipments data for the manufacturing energy groups (three-digit NAICS) in Virginia. These electricity consumption estimates were then used to estimate the share of the industrial sector electricity consumption for each sub-sector.

Preparation of Baseline Industrial Electricity Forecast

As is the case for state-level energy consumption data, no state-by-state disaggregated electricity consumption forecasts are publicly available. Several alternate data sources were used to calculate estimated electricity consumption growth rates for each state and sub-sector. We made the assumption that electricity consumption will be a function of gross state value of shipments (VOS). Electricity consumption, however, will not grow at the same rate as value of shipments. This is because in general, energy intensity (energy consumed per value of output) decreases with time.

Because state-level disaggregated economic growth projections are not publicly available, data was used from Moody's Economy.com. The average growth rate for specific industrial-subsectors was estimated based on Economy.com's estimates of gross state product. We used this estimated industrial electric consumption distribution to apportion the EIA estimate (2005) of industrial electricity consumption.

Twelve manufacturing sub-sectors, along with agriculture, mining, and construction, were chosen to represent industrial electricity use in Virginia (Table C.5). The manufacturing (NAICS 31-33) sub-sectors include beverage & tobacco products, transportation equipment, food, chemicals, plastics & rubber, computer and electronic products, paper, fabricated metal products, textile mills, wood products, machinery, and printing & related support activities. In order to simplify the analysis and to obtain information that would be of greatest significance to the state, only sub-sectors with value of

[4] The industry sector is comprised of four sub-sectors: Manufacturing, Mining, Agriculture, and Construction. Each sub-sector is further broken down into individual industry groups reflecting the many different definitions for the term 'industrial.'

shipments greater than 3% of total Virginia's industrial sector were included. In order to provide more insight and to match available data, two manufacturing sub-sectors were further analyzed. Beverage and tobacco manufacturing was broken down to separate beverage manufacturing and tobacco manufacturing, and chemical manufacturing was broken down into pharmaceuticals manufacturing and all other chemical manufacturing. These fifteen industrial sub-sectors account for almost 90% of Virginia's total industrial value of product shipments.

Table C.5. Base-Case Electricity Consumption by Industry in Virginia (Calibrated to 2002 Electric Power Annual)

NAICS Code	Industry Name	Base-Case Electricity Consumption (M kWh)	Percent of Total Industrial Consumption
11-13	Agriculture	555	2.8%
21	Mining	809	4.1%
23	Construction	1,141	5.8%
312	Beverage & tobacco product mfg	1,915	9.7%
3121	*Beverage*	*957*	
3122	*Tobacco*	*957*	
336	Transportation equipment mfg	1,098	5.5%
311	Food mfg	1,146	5.8%
325	Chemical mfg	5,264	26.6%
3254	*Pharmaceutical & medicine mfg*	*2,053*	
325x	*All other chemical products*	*3,211*	
326	Plastics & rubber products mfg	1,069	5.4%
334	Computer & electronic product mfg	733	3.7%
322	Paper mfg	1,375	6.9%
332	Fabricated metal product mfg	305	1.5%
313	Textile mills	543	2.7%
321	Wood product mfg	538	2.7%
333	Machinery mfg	267	1.3%
323	Printing & related support activities	430	2.2%
	Other Manufacturing	2,628	13.3%
Total Industrial Consumption		19,814	

Market Characterization Results

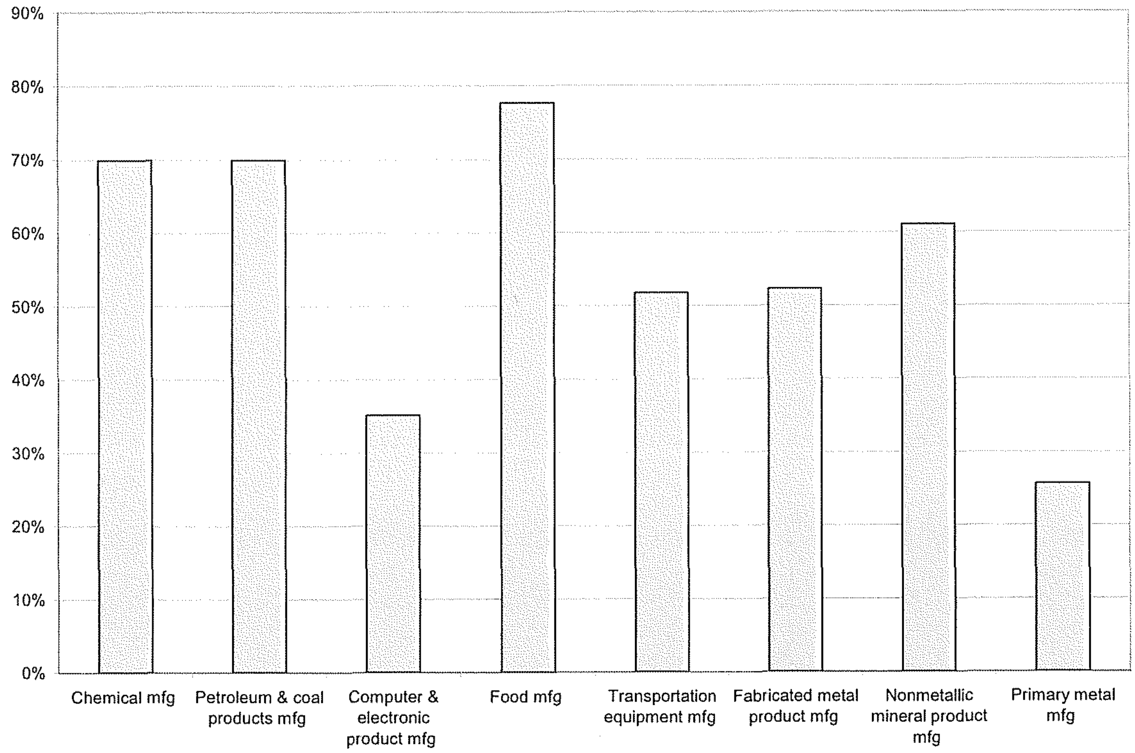
In 2008, the State of Virginia industrial sector consumed 19,814 GWh of electricity. Within the manufacturing sector, chemical manufacturing (NAICS 325) was the single largest electricity user with 26.6% of the electricity use, followed by beverage and tobacco products (NAICS 312) with 9.7% of industrial electricity use.

C.3.3. Industrial Electricity End Uses

In order to determine the electricity savings for any technology, the fraction of the electricity to which the technology is applicable must be determined. Much of the energy consumed by industry is directly involved in processes required to produce various products. Electricity accounts for about a third of the primary energy used by industries (EIA 2005). Electricity is used for many purposes, the most important being to run motors, provide lighting, provide heating, and to drive electrochemical processes.

While detailed end-use data is only available for each manufacturing sub-sector and group through the MECS survey (EIA 2005), motor systems are estimated to consume 60% of the industrial electricity (Xenergy 1998). The fraction of total electricity attributed to motors is presented in Figure C.6.

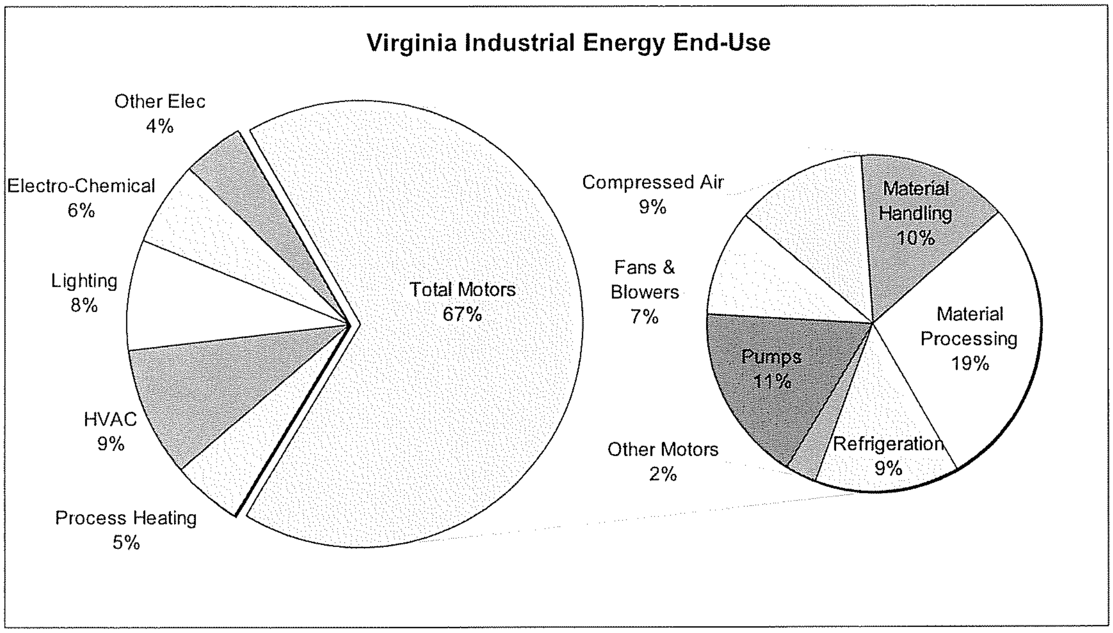
Figure C.6. Percent of Total Electricity Consumption by Motor Systems



Source: XENERGY (1998)

Motors are used for many diverse applications from fluid applications (pumps, fans, and air and refrigeration compressors), to materials handling and processing (conveyors, machine tools and other processing equipment). The distribution of these motor uses varies significantly by industry, with material processing being the largest consumer in the sector. Figure C.7 shows the total weighted average of end-use electricity consumption in Virginia with a breakdown of motors use in the state.

Figure C.7. Weighted Average of Total Industrial Electricity End-Uses in Virginia with Breakdown of Industrial Motor System End-Uses



While lighting and space conditioning represent a relatively small share of the overall industrial sector electricity consumption, they are important in some of the key industries found in the region such as transportation equipment manufacture and computer and electronics manufacturing, and the electricity savings potential can be significant.

C.3.4. Overview of Efficiency Measures Analyzed

The first step in our technology assessment was to collect limited information on a broad "universe" of potential technologies. Our key sources of information included the U.S. Department of Energy, Office of Industrial Technologies; the Center for the Analysis and Dissemination of Demonstrated Energy Technologies (CADDET); Lawrence Berkeley National Laboratory (LBNL) and American Council for an Energy-Efficient Economy reports; and information from NYSERDA. We did not collect any primary data on technology performance.

Oftentimes, no one source provided all of the information we sought for our assessment (energy use, energy savings compared to average current technology, investment cost, operating cost savings, lifetime, etc.). We therefore made our best effort to combine readily available information along with expert judgment where necessary.

We identified 14 measures that were cost effective at the average projected industrial electricity rates in Virginia of $0.07/kWh (Table C.6). The cost and performance of these measures has been developed over the past decade by ACEEE from research into the individual measures and review of past project performance. The costs of many of these measures has increased in recent years as a result of significant increases in key commodity costs such as copper, steel and aluminum, as well as overall manufacturing costs due to energy prices and market pressures. The estimates presented in Table C.6 represent ACEEE most current estimates. We present the full normalized installed measure cost (i.e., the full cost required to install a measure per unit of saved energy) as well as the levelized cost (i.e., the annual cost of the measure amortized over the life of the measure).

Table C.6 Cost and Performance of Industrial Measures

		Cost of Saved Energy		
Measure	Measure Life	Installed Cost/kWh	Levelized cost/kWh	Annual Savings for End-Use
Sensors & Controls	15	0.145	0.014	3%
EIS	15	0.635	0.061	1%
Duct/Pipe insulation	20	0.653	0.052	20%
Electric supply	15	0.104	0.010	3%
Lighting	15	0.212	0.020	23%
Advanced efficient motors	25	0.491	0.035	6%
Motor management	5	0.079	0.018	1%
Lubricants	1	0.000	0.000	3%
Motor system optimization	15	0.097	0.009	1%
Compressed air manage	1	0.000	0.000	17%
Compressed air - advanced	15	0.001	0.000	4%
Pumps	15	0.083	0.008	20%
Fans	15	0.249	0.024	6%
Refrigeration	15	0.034	0.003	10%

In addition, we estimated the average normalized cost of industrial energy efficiency investments to be $0.29/kWh saved. This estimate was arrived at by estimating the sum of the annual incremental savings for each measure in each industry based on end-use energy distribution and dividing the corresponding total investment required.

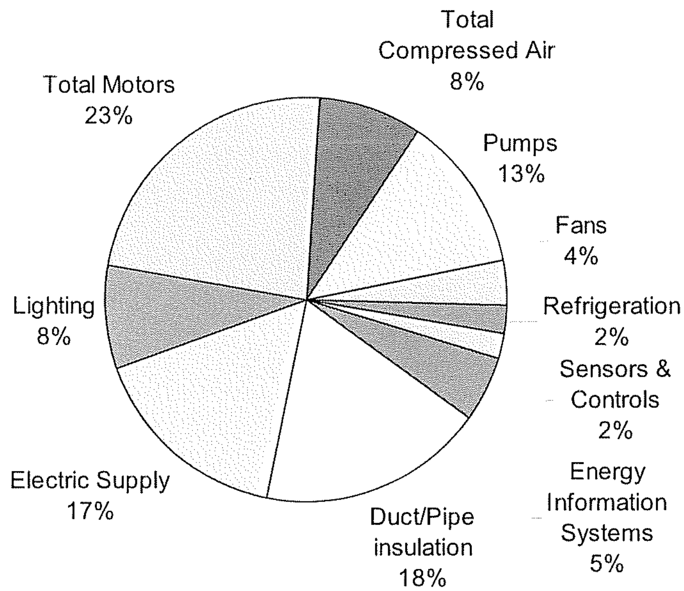
C.3.5. Electricity Savings Potential: Potential for Energy Savings

We sought to identify technologies that could have a large potential impact in terms of saving energy. These may be technologies that are specific to one process or one industry sector, or so-called "cross-cutting" technologies that are applicable to a variety of sectors. In estimating energy savings, we first identified the specific energy savings of each technology by comparing the energy used by the efficient technology to the energy required by current processes. Our second step was to "scale up" this savings estimate to see how much energy savings—for industry overall—this technology would achieve. For the most part, we derived specific energy savings information from the various technology assessment studies noted above.

In scaling up the technology-specific energy savings, we relied on our general knowledge of the various industrial processes to which this technology could be applied. We also took into account structural limitations to the penetration of the technology. Additionally, we recognized that market penetration, in the absence of significant policy support, can take time given the slowness of stock turnover in many industrial facilities.

In Virginia, a diverse set of efficiency measures will provide electricity savings for industry. The application of these measures contributes to total economic savings potential of 18%. These savings are distributed as presented in Figure C.9.

Figure C.9. Fraction of Savings Potential by Measure - Virginia



In addition, this analysis did not consider process-specific efficiency measures that would be applied at the individual site level because available data does not allow this level of analysis. However, based on experience from site assessments by U.S. Department of Energy and others entities, we would anticipate an additional economic savings of 5-10%, primarily at large energy intensive manufacturing facilities. Therefore, the overall economic industrial efficiency resource opportunity is on the order of 23-28%.

Appendix D - Demand Response Analysis

D.1.Introduction

This report defines Demand Response (DR), assesses current DR activities in Virginia, identifies policies in the commonwealth that impact DR, uses benchmark information to assess DR potential in Virginia, and identifies barriers in the commonwealth that might keep DR contributing appropriately to the resource mix that can be used to meet electricity needs. The analysis concludes with identification of policy recommendations regarding DR.

D.1.1. Objectives of this Assessment

This assessment develops estimates of DR potential for Virginia. Potential load reductions from DR are estimated for the residential, commercial, and industrial sectors (see Section 3). The assessment also includes discussions of reductions possible from other DR programs, such as DR rate designs (see Section 3.6).

D.1.2. Role of Demand Response in Virginia's Resource Portfolio

The DR capabilities developed by Virginia utilities will become part of a long-term resource strategy that includes resources such as traditional generation resources, renewable energy, power purchase agreements, options for fuel and capacity, energy efficiency and load management programs. Objectives include meeting future loads at lower cost, diversifying the portfolio to reduce operational and regulatory risk, and allow Virginia customers to better manage their electricity costs. The growth of renewable energy supply (and plans for increased growth) can increase the importance of DR in the portfolio mix. For example, sudden renewable energy supply reductions (e.g., from an abrupt loss in wind) may be mitigated quickly with DR.

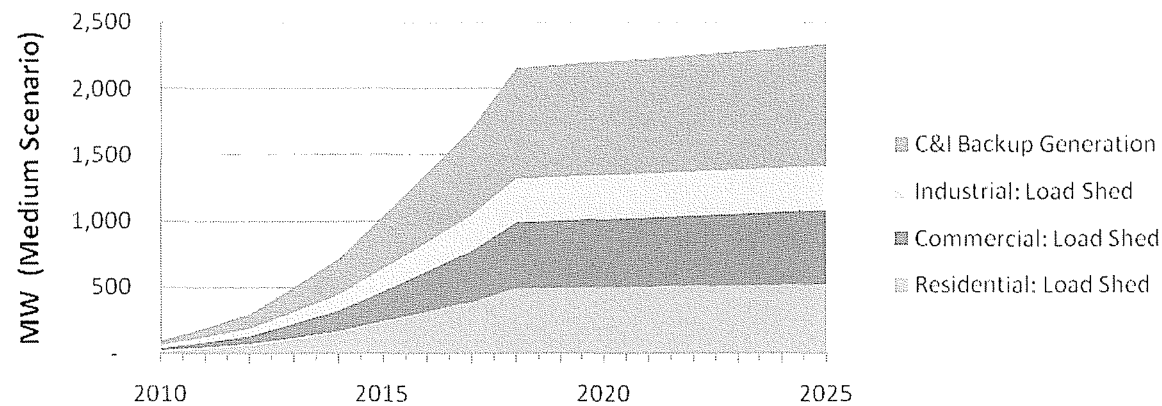
D.1.3. Summary of DR Potential Estimates in Virginia

Table D-1 shows the resulting load shed reductions possible for Virginia, by sector. The high scenario DR load potential reduction is within a range of reasonable outcomes in that it has an eleven year rollout period (beginning of 2010 through the end of 2020), providing a relatively long period of time to ramp up and integrate new technologies that support DR. A value nearer to the high scenario than the medium scenario would make a good MW target for a set of DR activities. The high scenario results show a reduction in peak demand of 1,566 MW (5.4% of 2015 peak demand) is possible by 2015; 3,332 MW (10.8% of 2020 peak demand) is possible by 2020; and 3,537 MW (10.8% of 2025 peak demand) is possible by 2025. The more conservative medium scenario results show a reduction in peak demand of 1,038 MW (3.6% of 2015 peak demand) is possible by 2015; 2,209 MW (7.2% of 2020 peak demand) is possible by 2020; and 2,345 MW (7.2% of 2025 peak demand) is possible by 2025. Load impacts grow rapidly through 2018 as program implementation takes hold. After 2018, the program impacts increase at the same rate as the forecasted growth in peak demand.

Table D-1. Summary of Potential DR in Virginia, By Sector, for Years 2015, 2020, and 2025[a]									
	Low Scenario			Medium Scenario			High Scenario		
	2015	2020	2025	2015	2020	2025	2015	2020	2025
Residential (MW)	143	299	310	238	499	516	333	699	723
Commercial: Load Shed (MW)	88	194	213	235	517	567	441	970	1,063
Industrial: Load Shed (MW)	72	145	147	162	327	331	289	582	588
C&I Backup Generation (MW)	302	639	698	402	865	930	503	1,082	1,163
Total DR Potential (MW)	605	1,288	1,367	1,038	2,209	2,345	1,566	3,332	3,537
DR Potential as % of Total Peak Demand (30,065 MW)	2.1%	4.2%	4.2%	3.6%	7.2%	7.2%	5.4%	10.8%	10.8%
a. See Section 3 for underlying data and assumptions.									

Figure 1 shows the resulting load shed reductions possible for Virginia, by sector, from year 2010, when load reductions are expected to begin, through year 2025.

Figure D-1. Potential DR Load Reductions in Virginia by Sector (MW)



These estimates reflect the level of effort put forth and utilities are recommended to set targets for the high scenarios. These estimates are based on assumptions regarding growth rates, participation rates, and program design. These factors are discussed in Chapter 3. In developing these DR potential estimates, the integration of DR with select energy efficiency activities was considered to help ensure that load impacts were not double counted. The estimated load reduction per program participant is conservatively estimated to account for increased energy efficiency in the future.

D.2.Defining Demand Response

DR focuses on shifting energy from peak periods to off-peak periods and clipping peak demands on days with the highest demands. Within the set of demand-side options, DR focuses on clipping peak demands that may allow for the deferral of new capacity additions, and it can enhance operating reserves available to mitigate system emergencies. Energy efficiency focuses on reducing overall energy consumption with attendant permanent reductions in peak demand growth. Taken together, these two demand-side options can provide opportunities to more efficiently manage growth, provide customers with increased options to manage energy costs, and develop least cost resource plans.

DR is an increasingly important tool for resource planning as power plant siting has grown more difficult and the costs of peak power have increased. Through development of DR capability, utilities can complement existing energy efficiency programs with a set of offerings that provide, at a minimum, 1) enhanced reliability, 2) cost savings, 3) reduced operating risk through resource diversification, and 4) increased opportunities for customers to manage their electric bills.

DR resources are usually grouped into two types: 1) load-curtailment activities where utilities can "call" for load reductions; and 2) price-based incentives which use time-differentiated and/or dispatchable rates to shift load away from peak demand periods and reduce overall peak-period consumption. Interest in both types of DR activities has increased across the country as fuel input prices have increased, environmental compliance costs have become more uncertain, and investment in overall electric infrastructure is needed to support new generation resources.

The mechanisms that utilities may use to achieve load reductions can range from voluntary curtailments to mandatory interruptions. These mechanisms include, but are not limited to:

- Direct load control by the utility using radio frequency or other communications platforms to trigger load devices connected to air conditioners, electric water heaters, and pool pumps;
- Manual load curtailments at commercial and industrial (C&I) facilities, including shutting off production lines and dimming overhead lighting;
- Automated DR ("Auto-DR") technologies utilizing controls or energy management systems to reduce major C&I loads in a pre-determined manner (e.g., raising temperature set points and reducing lighting loads); and
- Behavior modifications such as raising thermostat set points, deferring electric clothes drying in homes, and reducing lighting loads in commercial facilities.

D.3.Rationale for Demand Response

DR alternatives can be implemented to help ensure that a utility continues to provide reliable electric service at the least cost to its customers. Specific drivers often cited for DR include the following:

- **Ensure reliability**—DR provides load reductions on the customer side of the meter that can help alleviate system emergencies and help create a robust resource portfolio of both demand-side and supply-side resources that meet reliability objectives.

- **Reduce supply costs**—DR may be a less expensive option per megawatt than other resource alternatives. DR resources compete directly with supply-side resources in many regions of the country. Portfolios that help lower the increase in customers' expenditures on electricity over time represent an increasingly important attribute from the perspective of many energy customers.

- **Manage operational and economic risk through portfolio diversification**—DR capability is a resource that can diversify peaking capabilities. This creates an alternative means of meeting peak demand and reduces the risk that utilities will suffer financially due to transmission constraints, fuel supply disruptions, or increases in fuel costs.

- **Provide customers with greater control over electric bills**—DR programs would allow customers to save on their electric bills by shifting their consumption away from higher cost hours and/or responding to DR events. The ability to manage increases in energy costs has increased in importance for both residential and commercial customers. Standard residential and commercial tariffs provide customers with relatively few opportunities to manage their bills.

- **Address legislative/regulatory interest in DR**—Electric utility legislation enacted in April 2007 set a statutory goal for the commonwealth to save 10% of Virginia's total 2006 electricity sales by 2022 (H.B. 3068 and S.B. 1416, commonly referred to as electricity "re-regulation" legislation). This goal is estimated to total about 11 billion kWh, based on federal Energy Information Administration data for the 2006 base year (VCSS 2008). While the legislation focuses on an energy consumption goal, the Virginia State Corporation Commission Energy Efficiency Working Group has stated that reducing peak demand is also an important consideration (SCC 2008c).

DR is gaining greater acceptance among both utilities and regulators in the United States. A 2006 FERC survey found that 234 "entities" were offering direct load control programs and the FERC's assessment noted that "there has been a recent upsurge in interest and activity in DR nationally and, in particular, regional markets" (FERC 2006).[5] The recent proliferation of DR offerings has been promoted in part by utilities hoping to reduce system peaks while offering customers more control over electric bills and in part by regulators. Although federal legislation has not been the driver behind the trend, it is one of many indications, at all levels of government and industry, of the growing support for DR.[6]

Many states experience significant reductions in peak demand from Demand-Side Management (DSM) programs (which include DR programs). Regulatory filings show that California experienced 495 MW in peak demand reductions in 2005 (1% of total peak demand); New York experienced 288 MW reductions in 2005 (1% of total peak demand); and Texas experienced 181 MW in reductions in 2005 (1% of total peak demand) from DSM programs. These results are annual values that do not consider the cumulative (i.e., year-to-year) impacts that accrue over the lifetimes of the conservation measures. Therefore, cumulative percentage reductions in peak demand are much higher than the annual figures stated.

D.4.Assessment Methods

As has been shown in numerous other jurisdictions across North America, well-designed DSM programs incorporating DR strategies represent an effective and affordable option for reducing peak demand and meeting growing demand for electricity. This effort estimated conservative peak demand reduction for Virginia using local energy use characteristics, demographics, and forecast peak demand, assuming relatively basic DR strategies comprising responsive reductions in demand. The following research approach was used to conduct the analysis:

- Review of existing information regarding Virginia's customer base including:
    - Customer counts and average annual energy consumption by market segment;
    - Forecasts of future energy consumption and customer counts by market segment;
    - Previous DSM planning and potential studies.
- Review of additional publicly-available secondary sources including:

[5] The FERC report uses the term "entities" to refer to all types of electric utilities, as well as organizations such as power marketers and curtailment service providers.

[6] The federal Energy Policy Act of 2005 (EPAct) directs the Secretary of Energy to "identify and address barriers to the adoption of demand response programs," and the Act declares a U.S. policy in support of "State energy policies to provide reliable and affordable demand response services." EPAct directed FERC to conduct its survey of DR programs and also directed the U.S. Department of Energy to report on the benefits of DR and how to achieve them (DOE, 2006). Separately, a *National Action Plan for Energy Efficiency,* which advocates DR and other efficiency efforts, was developed by more than 50 U.S. companies, government bodies, and other organizations, including co-chairs Diane Munns, President of NARUC and Jim Rogers, President and CEO of Duke Energy (U.S. Environmental Protection Agency, 2006). Other utility industry members of the Leadership Group included Southern Company, AEP, PG&E, TVA, PJM Interconnection, ISO New England, and the California Energy Commission.

  - U.S. DOE's Commercial Building Energy Consumption Survey (CBECS) and Residential Energy Consumption Survey (RECS) data;
  - Previous studies relevant to the current effort completed by Summit Blue in other regions as well as entities in other jurisdictions.
- Development of baseline profiles for residential and commercial customers. These profiles include current and forecast numbers of customers by market segment and electricity use profiles by segment.
- Incorporation of ACEEE baseline data and reference case into analysis.
- Obtaining state-level data when possible and estimation of information for the Commonwealth of Virginia, when state-level data was not available.
- Development of a spreadsheet approach for estimating peak demand reduction potential associated with the DR programs/technologies deemed to be most applicable to Virginia. Estimates are developed for three scenarios—low, medium and high case scenarios.
- Conference calls with ACEEE staff and industry professionals to discuss assessment processes and legislative, regulatory, and other factors specific to the Commonwealth of Virginia.
- Incorporation of all sources of information and references into report, noting on each figure the source of the information.
- Revision of draft report based on comments from ACEEE, industry specialists and utility commenters.

The DR potential estimated used historical data and experience to obtain curtailment levels. This potential is assumed to be the achievable potential that would be cost effective, given the range of incentives that are typically required and the range of the utilities' avoided costs. A cost-effectiveness analysis was not performed for this study. Sufficient incentives could be provided to customers to encourage load reductions while maintaining a cost-effective program given avoided costs in the range of \$70-\$75 per kW (based on the analysis reference case).

Commonwealth of Virginia - Background

A sound strategy for development of DR resources requires an understanding of Virginia's demand and resource supply situation, including projected system demand, peak-day load shapes, and existing and planned generation resources and costs.

VA utilities serve more than three million residential facilities and more than 390,000 non-residential facilities, providing power that is expected to have a system peak load of close to 24,000 MW in 2008. The service territory is characterized by high population and load growth, the majority of which is attributable to new residents. Since 2000 the commonwealth has grown in population by 8%, compared to 6% for the United States as a whole. The impact of population growth on electricity demand is compounded by the fact that *electricity consumption per customer* has risen significantly in the past several decades.

All of Virginia is located with the PJM regional transmission organization, the largest power region in the US with installed capacity of over 164,000 MW. PJM covers 11 states including Pennsylvania, New Jersey, Maryland, Delaware, Virginia, West Virginia and parts of Ohio, Indiana, Illinois, Michigan and North Carolina. See Section 2.2 for a discussion of PJM's DR programs.

Dominion Virginia Power (Dominion) is the largest utility in Virginia, supplying over 90% of total new generation for the Commonwealth (EIA 2006a). Demand is growing faster in Dominion's Virginia service territory than anywhere else in the 13 states served by PJM (Dominion 2008b).

PJM projects that the peak demand for electricity in Dominion's service area will grow by almost 1,800 megawatts in just five years—the equivalent, in PJM's estimation, of adding one million homes to the system. Dominion's own studies project it will need 4000 MW of new capacity in ten years. This growth will impose severe strains on Virginia's electric system (Dominion 2008b).

D.4.1. Assessment of Utility DR Activities

Virginia has had some of the lowest electricity rates in the county and, until recent years, has had adequate capacity to meet the Commonwealth's electricity needs. As a result, interest in energy efficiency and DR in Virginia has been limited in past years. Current conditions are changing. Capacity is being strained and electricity costs are increasing. Rising electricity costs stem from a combination of rising consumption, necessitating new investment in generation and transmission, increases in fuel costs, and the potential for additional environmental restrictions. The elimination of price caps and potentially higher fuel prices will increase the importance in assessing future resources and DR potential.

Utility-specific information on DR participation in Virginia is not readily available. The Appalachian Power Company (APCO) stated that they have not determined the DR from residential and small commercial customer programs, but do have a prevalence of 70.9 MW of distributed generation, and the participation of one large industrial customer on a real-time pricing type rate with approximately 11MW subject to interruption (APCO 2008). The Company has not quantified other industrial DR levels, but customers are provided time-of-day demand rates and shift load to take advantage of off-peak demand rates.

Dominion has stated that in June of 2008, they introduced an aggressive energy conservation and demand reduction plan that it intends to offer Virginia customers, subject to Commission approval. The plan includes DR programs such as residential AC and heat pump cycling and incentives for commercial customers who install back-up generators available for dispatch during peak demand periods (Dominion 2008a).

The PJM Interconnection (PJM), a regional transmission organization (RTO) containing the entire commonwealth of Virginia, provides opportunities for DR to realize value for demand reductions in the Energy, Capacity, Synchronized Reserve, and Regulation markets. The FERC authorized PJM to provide these opportunities as permanent features of these markets in early 2006 (PJM 2008a).

The PJM Economic Load Response Program enables customers to voluntarily respond to PJM Locational Marginal Price ("LMP") prices by reducing consumption and receiving a payment for the reduction. The growth of participation by end-use customers since 2002 is significant, with over 225,000 MWh of participation in 2006 (PJM 2008a). PJM's Load Response Activity Report of July 2008 reported 50 sites in their Economic Program in Virginia, including 237.4 MW (PJM 2008c). The report also states 190 sites and 176.7 MW are included in their Emergency ILR and DR programs.

Under the Reliability Pricing Model (RPM), customers can offer DR as a forward capacity resource. DR providers can submit offers to provide a demand reduction as a capacity resource in the forward RPM auctions. In the first annual RPM auction which was held in April 2007 for the 2007/2008 planning period, 127.6 MW of demand response offers were cleared (PJM 2008a).[7]

[7] It is not known what portion of PJM DR reductions have been fulfilled by Virginia customers. [NOTE: These data are forthcoming, but it is not expected that Virginia currently provides larger contributions to this PJM DR resource. For this analysis, 250 MW of demand response was assumed to be currently available in Virginia. The DR potential ramp rate numbers in the figures start at 250 MW to recognize what is believed to be a reasonable estimate of existing DR.

PJM held a symposium on DR in May, 2007 that was attended by a broad mix of stakeholders and subject matter experts. One of the most prominent themes to emerge from the symposium was the need for coordination between retail and wholesale markets in order to increase DR participation in PJM's markets. The participants at the PJM Symposium on DR identified priority opportunities, which formed the basis of a "Demand Response Roadmap" to guide action (PJM 2008b).

D.4.2. Assessment of Current Commonwealth Policies Affecting DR

Electric utility legislation enacted in April 2007 (H.B. 3068 and S.B. 1416, commonly referred to as electricity "re-regulation" legislation) set a statutory goal for the commonwealth to save 10% of Virginia's total 2006 electricity sales by 2022. The legislative language is as follows:

> The Commonwealth shall have a stated goal of reducing the consumption of electric energy by retail customers through the implementation of such programs by the year 2022 by an amount equal to ten percent of the amount of electric energy consumed by retail customers in 2006.
>
> The State Corporation Commission shall conduct a proceeding to determine whether the ten percent electric energy consumption reduction goal can be achieved cost-effectively through the operation of such programs, and if not, determine the appropriate goal for the year 2022 relative to base year of 2006,
>
> In developing a plan to meet the goal, the Commission may consider providing for a public benefit fund and shall consider the fair and reasonable allocation by customer class of the incremental costs of meeting the goal. This goal is estimated to total about 11 billion kWh, based on federal Energy information Administration data for the 2006 base year.

Reservations about DSM that the Virginia State Corporation Commission (SCC) may have had under the price-capped transition to retail competition are not likely continue since that transition has been abandoned in the new "re-regulation" bill. In particular, the bill:

- Provides incentives for utilities to find renewable forms of energy and establish demand-side management and conservation programs;
  Allows each utility to seek rate adjustment clauses to recover costs of FERC-approved demand response programs and costs of providing incentives for the utility to design and implement demand-side management programs; and
- Directs the SCC to "conduct a proceeding to establish goals for the amount of energy and demand to be reduced by the operation of demand-side management, conservation, energy efficiency, and load management programs, and develop a plan for the development and implementation of recommended programs."

More recently Governor Kaine issued Executive Order 48 that directs the Commonwealth's executive Branch to reduce the annual cost of energy purchases from non-renewable sources by at least 20% by fiscal year 2010. These initiatives provide the Commonwealth with an opportunity to integrate cost-effective demand- and supply-side options into system planning processes. This directive could create business opportunities for independent vendors of DSM programs and technologies.

The SCC was directed by the General Assembly to conduct a proceeding and submit its findings and recommendations for any additional legislation necessary to implement the plan to meet the energy consumption reduction goal. The SCC's sub-group 3 claimed that "new opportunities exist to capture the potential for reductions in peak demand resulting from recent policy enhancements within the PJM Interconnection, advances in telecommunications allowing real-time communication, and improvements in the affordability and functionality of DR technology. This sub-group found that increased deployment of DR in the Commonwealth could yield substantial customer financial benefits and electric reliability benefits. Historically, the focus on the utility industry in Virginia, as in most jurisdictions, has been on supply-side, rather than demand-side, solutions to address peak demand. As a result, generating plants and transmission lines have been and continue to be relied upon to meet peak loads during the limited hours of the year in which these loads occur... Staff believes that it is advisable for Virginia's electric utilities to develop a current integrated resource plan that considers supply and demand resources for the Commonwealth and to thus determine the value of avoided electrical supply costs" (SCC 2007).

Sub-group 3 identified institutional and infrastructure barriers to DR, including:

- Fragmentation in the industry and government regulatory oversight.
- Lack of customer education.
- Lack of clarity and coordination between the Federal and State agencies and programs.
- Lack of standards.
- Lack of consideration of societal benefits, including environmental benefits of most forms of DR.
- Difficulty in navigating DEQ requirement, making it hard for users to utilize customer owned, otherwise idle, generation capability (SCC 2007).

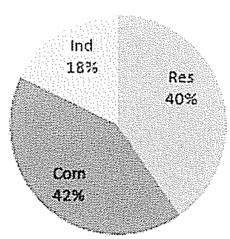
The sub-group developed a list of recommendations to address these barriers, and to reduce other existing impediments to DR programs including:

- Lack of perceived need for DR;
- Incentives and cost recovery;
- Fragmentation in the industry and government regulatory oversight;
- Concern about the potential economic and operational impact of DR on industrial customers; and
- Rate design (SCC 2007).

D.4.3. Energy and Peak Demands

Use of energy in Virginia is distributed to end use categories as follows: 42% commercial, 40% residential, and 18% industrial sectors (see Figure 2).

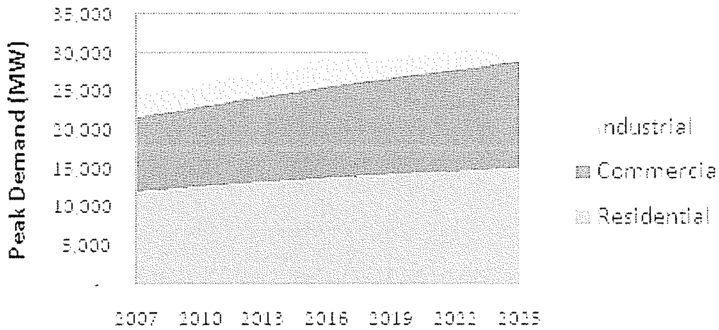
Figure D-2. Energy Sales in Virginia by Sector (2006)



Source: EIA (2006a)

In 2007, the total summer peak load was 25,200MW and is projected to grow an average of 1.46% per year through 2025. Figure 3 displays peak demand by sector. In 2007, residential peak demand was 11,892MW (47%); commercial was 9,791MW (39%); and industrial was 3,522MW (14%).

Figure D-3. Peak Demand by Sector in Virginia (MW)



Source: ACEEE Reference Case for Virginia

Air conditioning (AC) makes up the largest portion of peak demand needs in many states, primarily in southern states. For one utility in Florida, a confidential study revealed that in 2005, AC accounted for 67% of residential peak demand for single-family homes, and 62% for multi-family homes. For commercial and industrial peak demand, data from the California Commercial End-Use Survey 2005 shows that AC accounted for between 50 to 60 percent of peak demand for the following categories:

- College (59%)
- Health Care (58%)
- Large Office (56%)
- Hotel (53%)
- Small Office (51%)

AC use in warehouses only accounted for approximately 13% of peak demand, with lighting accounting for 50% and "other" accounting for 38%.

D.4.4. Smart Grids and Advanced Metering Infrastructure (AMI)

The 2005 Energy Policy Act provisions for Demand Response and Smart Metering has lead to a number of states and utilities piloting and implementing a Smart Grid, or sometimes referred to as Advanced Metering Infrastructure (AMI).

Smart Grid is a transformed electricity transmission and distribution network or "grid" that uses robust two-way communications, advanced sensors, and distributed computers to improve the efficiency, reliability and safety of power delivery and use. For energy delivery, the Smart Grid has the ability to sense when a part of its system is overloaded and reroute power to reduce that overload and prevent a potential outage situation. The end user is equipped with real-time communication between the consumer and utility allowing optimization of a consumer's energy usage based on environmental and/or price preferences (for example, critical peak pricing and time of use rates).

AMI provides:

- Two-way communication between the utility and the customer through the customer's smart meter.
- More efficient management of customer outages (location, re-routing).
- More accurate meter reading (minute, 15 minute intervals).
- More timely collection efforts (real time).
- Improved efficiency in handling service orders.
- More detailed, timely information about energy use to help customers make informed energy decisions (real time).
- Ability to reduce peak demand.
- More innovative rate options and tools for customers to manage their bills.

Smart Energy Pricing provides:

- Incentives to customers to shift energy away from critical peak periods
- The ability to for customers to save on their electricity bills.
- Lower wholesale prices for capacity and transmission—in the longer term.
- Improved electric system reliability, as demand is moderated.
- Potential to defer new transmission and generation.

The Smart Grid is comprised of multiple communication systems and equipment, which interoperability is crucial. Not all communication protocols are applicable to every utility's geography; therefore, pilots are essential in testing the equipment and communication software for various geographies. Furthermore, the identification of those geographic regions with the best return on investment during a pilot will aid the staged implementation plan. Standards are continuing to be researched through organizations including: 1) IntelliGrid—Created by the Electric Power Research Institute (EPRI); 2) Modern Grid Initiative (MGI) is a collaborative effort between the U.S. Department of Energy (DOE), the National Energy Technology Laboratory (NETL), utilities, consumers, researchers, and other grid stakeholders; 3) Grid 2030—Grid 2030 is a joint vision statement for the U.S. electrical system developed by the electric utility industry, equipment manufacturers, information technology providers, federal and state government agencies, interest groups, universities, and national laboratories; 4) GridWise—a DOE Office of Electricity Delivery and Energy Reliability (OE) program; 5) GridWise Architecture Council (GWAC) was formed by the U.S. Department of Energy; and 6) GridWorks—A DOE OE program.

Principal benefits of Smart Grid technologies for DR include increased participation rates and lower costs. In 2009, Dominion plans to deploy 200,000 smart meters as part of a large demonstration program of smart grid technology in urban and rural areas of Dominion's service territory. Dominion expects to improve customer service and business operations through advanced system control, real-time outage notification, and power quality monitoring. As part of this program, Dominion is deploying a number of smart thermostats for a residential critical peak pricing pilot during the summer of 2008. Dominion will measure customer responsiveness to changing energy prices and the impact on energy demand during peak usage periods.

These developments in technology allowing real time signaling and automated response will improve DR capabilities. However, existing technology exists for successful DR implementation and it is important to point out that there are no technology obstacles to effective DR.

D.5.Assessment of DR Potential in Virginia

This section examines and quantifies DR potential in Virginia. Section 3.1 outlines the general DR program categories, while Sections 3.2 and 3.3 outline the DR potential in the residential and commercial /industrial sectors, respectively. Section 3.4 discusses the load reduction potential from backup generation and Section 3.5 explains the issues surrounding rate pricing, even though benefits from this form of DR are not quantified in this analysis. Section 3.6 concludes with a summary of DR potential in Virginia.

D.5.1. Demand Response Program Categories

For the purposes of assessing DR alternatives, the following programs could be employed in Virginia to achieve the DR potential we outlined in this report:

Resource Category	Characteristics
Direct Load Control (DLC)	Direct load control (DLC) programs have typically been mass-market programs directed at residential and small commercial (<100 kW peak demand) air conditioning and other appliances. However, an emerging trend is to target commercial buildings with what has become known as Automated Demand Response or Auto-DR. Increased use and functionality of energy management systems at commercial sites and an increased interest by commercial customers in participating in these programs is driving growth in automated commercial curtailment in response to a utility signal. The common factor in these programs is that they are actuated directly by the utility and require the installation of control and communications infrastructure to facilitate the control process.
Callable Customer Load Response	With this type of program, utilities offer customers incentives to reduce their electric demand for specified periods of time when notified by the utility. These programs include curtailable and interruptible rate programs and demand bidding/buyback programs. Curtailable and interruptible rate programs can be used as "emergency demand response" if the advanced notice requirements are short enough. All customer load response programs require communications protocols to notify customers and appropriate metering to assess customer response.
Scheduled Load Control	This is a class of programs where customers schedule load reductions at pre-determined times and in pre-determined amounts. A variant on this theme is thermal energy storage which employs fixed asset technology to reduce air conditioning loads consistently during peak afternoon load periods.
Time-differentiated Rates	Pricing programs can employ rates that vary over time to encourage customers to reduce their demand for electricity in response to economic signals—in some cases these load reductions can be automated when a price trigger is exceeded. An example is a critical peak price which is "called" by the utility or system operator. In response to this critical price, residential customers can have AC cycling or temperature setbacks automatically deployed. Similar automated responses can be deployed by commercial customers. These rate programs are not analyzed for this assessment, but are further discussed in Section 3.5.

D.5.2. DR for Residential Customers

Air conditioner and other appliance direct load control (DLC) is the most common form of non-price-based DR program in terms of the number of utilities using it and the number of customers enrolled. According to FERC's 2006 assessment of DR and advanced metering, there are 234 utilities (including municipalities, cooperatives, and related entities) with DLC programs across the United States. Approximately 4.8 million customers are participating in DLC programs across the country (FERC 2006).

The prominent and growing role of air conditioning in creating system peaks makes it a high-profile candidate for DR efforts. The advances in DR technology that make AC load management economically viable make AC load control a high-priority program—one that has been proven reliable and effective at many utilities. Pool pumps are also a relatively easy and non-disruptive load that can be controlled for DR purposes.

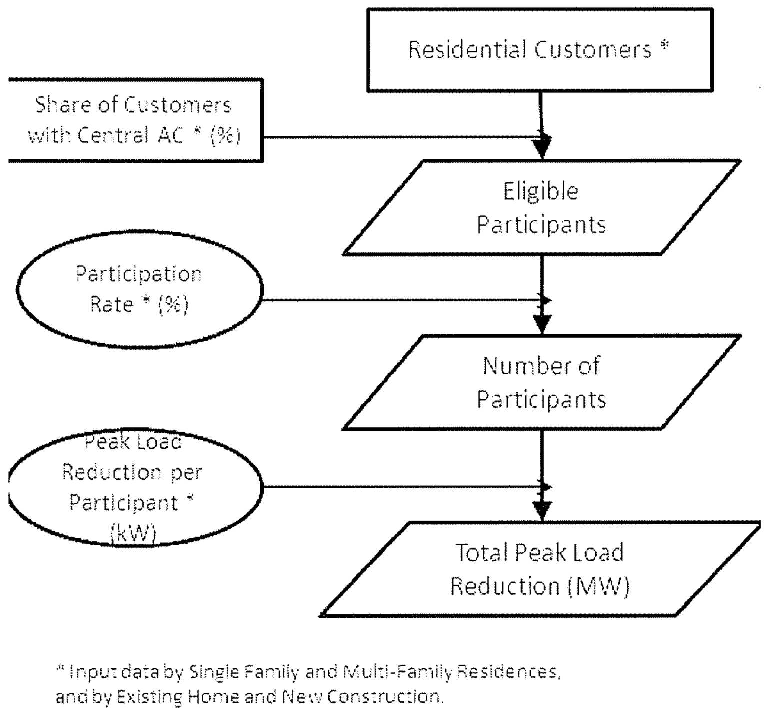
Residential Control Strategies

There are two basic types of control strategies: AC cycling and temperature offset. AC cycling limits ACs being on to a certain number of minutes than they otherwise would have been on. Some techniques limit ACs to being on for 50% of the minutes they would otherwise have been on. A temperature offset increases the thermostat setting for a certain period of time, for a certain number of degrees higher than it would have otherwise been set. This essentially causes the AC compressor to cycle as the temperature set-back reduces the AC demand. Sequential thermostat setbacks, i.e., one degree in a hour one, two degrees in hour two, three degrees in hour three, and four degrees in hour four can mimic an AC cycling strategy.

Cycling strategies have evolved where an optimal impact on peak kW demand may be obtained by varying the cycling time across the hours of an event. For example, there may be one hour of pre-cooling followed by 33% cycling in the first hour, 50% cycling in the second hour, 66% cycling in the third hour and dropping back to 33% in the fourth hour. Strategies like this have been deployed in pilot programs at Progress Energy Carolinas (PEC) and in PSE&G's MyPower pilot program. This type of strategy requires that forecasters accurately predict the hour(s) in which the peak system demand will occur.

<u>Assessment of DR Potential in Residential Homes in Virginia</u>
For Virginia, estimates for possible load reductions for residential housing units were obtained by applying the methodology displayed in Figure 4.

Figure D-4. Residential Peak Load Reduction



The figure shows how load reductions and participations rates are applied to housing data. Items listed in rectangular shapes are factual inputs; items in circular shapes are assumptions; and items in parallelogram shapes are results.

D.5.3. Load Reductions

Recent surveys show that DLC programs are being implemented by a number of utilities. Load impacts are dependent on many variables. The control strategy used, the outdoor temperature, the time of day, the customer segment, ease of and ability to override control, reliability of communication signals, age and working condition of installed equipment, and local AC use patterns all have significant effects on the load impact. Even within a single program, there is variability in impacts across event days that cannot yet be fully explained. Measuring impacts typically requires expensive monitoring equipment and as a result is often done on small sample sizes.

Even with this variability, a review of reported impacts does show some general consistencies. As expected, impacts increase as the duty cycle goes up. Table D-2 shows the average reported kW impact based on 20 load control impact studies for programs based on the duty cycle used. These results support the oft-quoted rule-of-thumb that the load impact for 50% duty cycling is 1 kW per customer, which is the impact used in this analysis. However, many homes will experience an impact greater than I kW, especially newer homes.

Table D-2. Average Load Impacts by Cycling Strategy for AC DLC Programs

Cycling Strategy	Average Load Impact KW/Customer
33%	0.74
45%	0.81
50%	1.04
66%	1.36

Source: Summit Blue 2007b

Customer type also makes a difference. In a few cases where single-family and multi-family impacts were measured separately, multi-family impacts were 60% of single-family, and thus a 0.6kW load reduction is applied in this analysis for multi-family units (Summit Blue 2007b).

Eligible Residential Customers

All residential customers with central air-conditioning that live in areas that can receive control signals are considered eligible for the direct load control program. This includes single family and multi-family housing units. Residential accounts without central AC are assumed to have no participation.

Multi-family housing units often have building tenants which are not the account holders, therefore accounts are often aggregated into buildings. Some accounts have a master meter for the entire building, including tenants. Some accounts are for the "common" building loads (i.e., those loads that are part of a building account such as elevators, A/C (if applicable), lobby lighting, etc.), but individual tenants in these buildings have their own accounts.

The analysis assumes 70% of single-family residences have central AC. This is considered a conservative estimate for Virginia, as Progress Carolinas experience 77%. Arizona residences experience 95%, but have higher average temperatures than Virginia. Multi-family units typically have fewer units with central AC than single family. The analysis assumes 63% of multi-family residences have central AC, as 63% was obtained for all housing units obtained from 2005 RECS data from the EIA, averaging the data between the South and Middle Atlantic Census Regions.

Residential Participation Rates

Participation rates experienced in AC DLC programs vary across utilities typically from 7% of eligible customers to 40%, depending upon the effort made in maintaining and marketing the program (Summit Blue 2007a). The utilities with the low levels of participation had essentially stopped marketing the program in recent years. Utilities with programs with sustained attention to customer retention or recruitment show higher participation rates than utilities with one-time or intermittent promotion. In Maryland, BG&E's Demand Response Service program anticipates a residential participation rate of 50%, or approximately 450,000 controlled units (BGE 2007). The pilot phase of this program was conducted from June 1 through September 30, 2007, and 58% received a "smart" load control switch, and 42% had a "smart" thermostat installed (BGE 2007). One study examined 15 AC DLC programs nationwide and found an average of 24% participation for eligible customers (Summit Blue 2008a).[8] For this analysis, 3 typical yet conservative scenarios were used: a low scenario of 15% for eligible customers; a medium scenario of 25%; and a high scenario of 35%.

Results

Table D-3 displays the input data and results. In summary, the results for residential programs are as follows:

- A medium scenario reduction of 238 MW is possible by 2015, and 499 MW by 2020;
- A low scenario reduction of 143 MW is possible by 2015, and 299 MW by 2020;
- A high scenario reduction of 333 MW is possible by 2015, and 699 MW by 2020.

Table D-3. Potential Load Reduction from AC-DLC In Virginia Residential Homes, in years 2015 and 2020

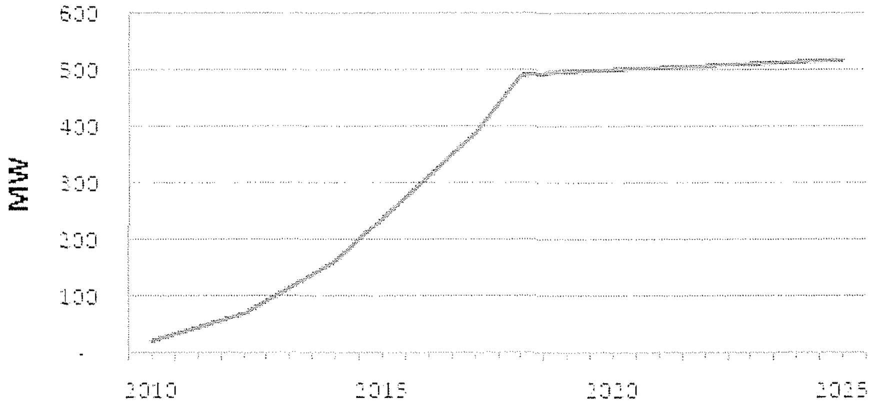
INPUTS		
Residential Peak Demand (MW)	14,300	
Residential Customers: Total [a]	3,463,276	
Residential Customers: Single Family [a]	2,164,854	
Residential Customers: Multi-Family [a]	1,271,422	
Eligible Residential Customers: Single Family [b,c]	1,515,398	
Eligible Residential Customers: Multi-Family [b,d]	800,996	
Load Reduction per AC-DLC per Single-Family Unit (kW)	1.0	
Load Reduction per AC-DLC per Multi-Family Unit (kW)	0.6	
DR Participation Rate (of eligible customers): Low	15%	
DR Participation Rate (of eligible customers): Medium	25%	
DR Participation Rate (of eligible customers): High [d]	35%	
RESULTS	**2015**	**2020**
Residential Potential DR Load Reduction: Low (MW)	143	299
Residential Potential DR Load Reduction: Med (MW)	238	499
Residential Potential DR Load Reduction: High (MW)	333	699

Notes:
a. Residential customers reflect number of housing units, as reported from Economy.com.
b. Residential accounts without central AC are assumed to have no participation.
c. Analysis assumes 70% of single-family residences have central AC.
d. Analysis assumes 63% of multi-family residences have central AC.
d. Higher participation than applied in the High Scenario is possible through design of program features, such as "opt-out" participation where participants are included in a program unless they chose to "opt-out".

Figure 5 shows the resulting residential load shed reductions possible for Virginia, from year 2010, when load reductions are expected to begin, through year 2025.

[8] Programs where participants are included in a program unless they chose to "opt-out" experience much higher participation rates. One utility is proposing a "hybrid" program for new construction, where existing customers must opt-in and new construction customers must opt-out. This program assumes that 70% of new construction customers will enroll in the initial years, and 80% in later years (Summit Blue, 2008b).

Figure D-5. Potential Residential Load Shed in Virginia



D.5.4. Room Air Conditioners

Other DR residential programs could involve tapping into the potential for callable load reductions from room air conditioners. At least one prominent DR provider is exploring the possibility of having manufacturers of room AC units embedding a home-area-network communication device into new units. This would enable cycling of room air conditioners without the need to install radio frequency load switches commonly used for residential direct load control applications. Callable load reductions from room air conditioners would provide a significant boost to load control capability and these reductions would be dispatchable in less than ten minutes. Some utilities are projecting to add a large number of new room air conditioners in the next five to ten years. The additional participation of a fraction of these room AC units could provide a substantial increase to the AC DLC program.

D.5.5. Other Appliances

Based on the experiences of other utilities, expanding the equipment controlled to other equipment beyond AC units can produce additional kW reductions. This could include electric hot water heaters and pool pumps. However, the saturation of electric hot water heaters is lower than for air conditioning, and control of hot water heaters generally produces only about one-third the load impact of air conditioners, especially in the summer when Virginia utilities would most likely be calling DR events.

D.6.Commercial and Industrial DR Potential in Virginia

Appropriate commercial sector DR programs will vary according to customer size and the type of facility. Direct load control of space conditioner equipment is a primary DR strategy intended for small commercial customers (e.g., under 100 kW peak load), although TOU rates combined with promising new thermal energy storage technologies could prove an effective combination. Mid-to-large commercial customers and smaller industrial customers could best be targeted for a curtailable load program requiring several hours of advanced notification or, where practical, for an Auto-DR program that can deliver load reductions with no more than ten minutes of advance notice. Thermal energy storage and other scheduled load control programs may also be applicable for some larger buildings or water pumping customers. In this assessment of DR potential, the focus is on the use of direct load control and curtailable load response programs. Studies have shown that pricing programs, specifically dispatchable pricing programs such as critical peak pricing (CPP) programs can provide similar impacts. These pricing programs are discussed in Section 3.2. However, for the purposes of this assessment, a focus on these load response programs is believed to be able to fully represent the DR potential, even though pricing programs could be used instead of these curtailable load programs with equal, or in some cases, greater efficiency.

The following DR program descriptions apply to both commercial and industrial customers:

- Small business direct load control (air conditioning)—Small commercial customers (under 100 kW peak load) account for a majority of customer accounts but typically only about one-quarter of total commercial load. Due to the nature of small businesses, particularly their small staffs for which energy management is a relatively low priority, it is not practical to rely on active customer response to load control events. Thus, small businesses may best be viewed in the same way as residential customers for purposes of DR.
- Curtailable load program—This program would be applicable to commercial and industrial customers willing to commit to self-activated load reductions of a minimum of perhaps 50 kW in response to a notice and request from a utility. The minimum curtailment threshold is designed to improve program cost-effectiveness by ensuring that recruitment and technical assistance costs are used for customers who can deliver significant load reductions. Advanced notice requirements would likely be two hours— long enough to allow customers an opportunity to prepare but short enough to maintain the DR resource as a viable resource that can be dispatched by operations staff. Enabling technologies would vary greatly, but utilities would educate customers about alternatives and could work with equipment vendors to facilitate equipment acquisition and installation. Incentives would be paid as capacity payment (in $/kW-month) or a discount on the customers' demand charges. Utilities could also offer a voluntary version of the program to attract greater participation. Customers would not commit to load reductions, but incentives would be lower and would be paid only on the reductions achieved during curtailment events.
- Automated demand response (Auto-DR)—This program would be marketed to facilities such as high-rise office buildings and large retail businesses that have energy management and control systems (EMCS) that monitor and control HVAC systems, lighting, and other building functions. The benefits of Auto-DR over curtailable load programs include customer loads curtailments with as little as ten minutes notice and greater assurance that customers will reduce loads by at least their contracted amount. Incentives would be paid as either capacity payments or demand charge discounts, but would be greater than for curtailable load program participants due to the additional technology investment that may be required and the allowance of curtailments on relatively short notice. UTILITIES would offer extensive technical assistance in setting up Auto-DR capability and would potentially provide financial assistance as well for customers making long-term commitments.
- Scheduled load control programs (including thermal energy storage)—Scheduled load control can help reduce utility peak demand, especially through shifting of space cooling loads enabled by thermal energy storage technologies. Large-customer TES systems could be promoted along with customer commitments to reduce operation of chillers or rooftop air conditioners during specified peak hours. Customers' return on investment can be increased by encouraging migration to a TOU rate, which would offer a rate discount for many of the hours that TES systems are recharging cooling capacity. Water pumping systems are typically good candidates for scheduled load control programs and utilities can investigate opportunities in the municipal water supply and irrigation sectors. Other, less traditional, opportunities may also be available, such as the leisure/resort industry's limiting recharging of electric golf carts to off-peak hours.
- Emergency under-frequency relay (program add-on)—Under-frequency relays (UFRs) automatically shut off electrical circuits in response to the circuits exceeding pre-set voltage thresholds specified by the utility. Use of UFRs is a valuable addition to a DR portfolio because the load response is both automatic and virtually instantaneous. UFRs can best be integrated into another DR program where participants are already engaging in load curtailment activities. It is expected that some customers who might consider participating in a DR program will not be willing to allow loads to be controlled via UFR since they would not receive any advanced notice. Incentives would also need to be greater to attract participants and provide acceptable compensation. However, the benefits of UFRs warrant their consideration as part of a utility's proposed DR portfolio.

D.6.1. Commercial DR Potential in Virginia

To estimate potential load reductions for commercial units, a straight-forward approach of applying load shed participation rates and curtailment rates directly to commercial peak demand.

First, assumptions were made on the percentage of commercial customers who are willing to participate in DR programs. One study applied commercial participation rates ranging from 11% to 48% for commercial customers (Summit Blue 2008a). Table D-4 displays participation rates for various types of commercial customers, disaggregated into two different peak demand categories (<300kW and >300kW).

Table D-4. Examples of Commercial Load Shed Participation Rates

	Peak Category	
Customer Segment	<300kW	>300kW
Office Buildings	11% - 15%	45% - 48%
Hospitals	13%	48%
Hotels	14%	45%
Educational Facilities	13%	43%
Retail	11%	42%
Supermarkets	12%	33%
Restaurants	11%	39%
Other Government Facilities	15%	44%
Entertainment	13%	41%
Source: Summit Blue 2008a.		

Because facility-specific data was not available for Virginia, three conservative scenarios for participation rates were applied. A medium-scenario load participation rate of 20% was applied as it appears to be an average participation rate found by utilities with DR programs in place. A low scenario of 10% and a high scenario of 30% are applied.

Then, assumptions were made for curtailment rates, based on existing estimates of the fraction of load that has been shed by commercial customers enrolled in event-based DR programs callable by the utility. Table D-5 displays curtailment rates for various types of commercial customers, which range from 13% to 43%. For the purposes of this analysis, 3 conservative scenarios were applied: a low curtailment rate of 15%, a medium curtailment rate of 20%, and a high rate of 25%.

Table D-5. Examples of Commercial Curtailment Rates

Customer Segment	Average Curtailment Rate
Office Buildings	21%
Hospitals	18%
Hotels	15%
Educational Facilities	22%
Retail	18%
Supermarkets	13%
Restaurants	17%
Other Government Facilities	38%
Entertainment	43%
Source: Summit Blue 2008a.	

Table D-6 displays the input data and results. In summary, the commercial sector results are:

- A medium scenario reduction of 235 MW is possible by 2015, and 517 MW by 2020;

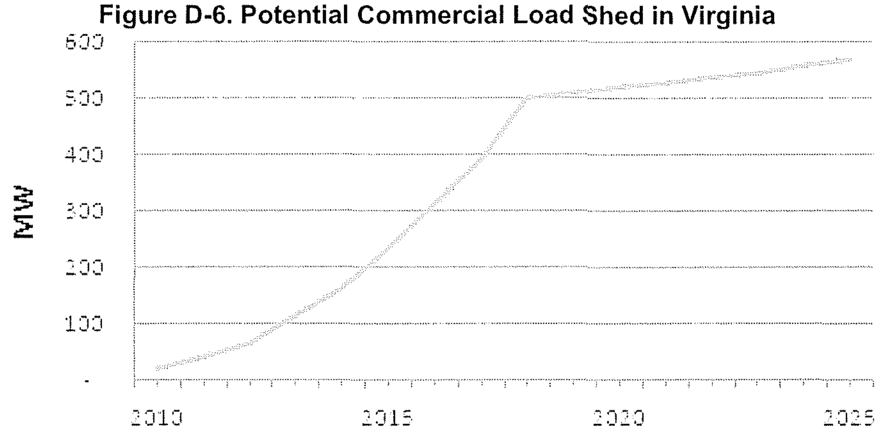
- A low scenario reduction of 88 MW is possible by 2015, and 194 MW by 2020;
- A high scenario reduction of 441 MW is possible by 2015, and 970 MW by 2020.

Table D-6. Potential Commercial Load Shed in Virginia, in Years 2015 and 2020

INPUTS		
Commercial Peak Demand (MW)	12,933	
Load Shed Participation Rate: Low	10%	
Load Shed Participation Rate: Medium	20%	
Load Shed Participation Rate: High	30%	
Curtailment Rate: Low	15%	
Curtailment Rate: Medium	20%	
Curtailment Rate: High	25%	
RESULTS	**2015**	**2020**
Commercial DR load reduction: Low (MW)	88	194
Commercial DR load reduction: Med (MW)	235	517
Commercial DR load reduction: High (MW)	441	970

Figure 6 shows the resulting commercial load shed reductions possible for Virginia, from year 2010, when load reductions are expected to begin, through year 2025.

Figure D-6. Potential Commercial Load Shed in Virginia



DR programs that move towards the auto-DR concept can typically provide some load sheds that only require ten-minute notification or less. While some customer surveys have shown that most customers would prefer longer notification periods, many of these customers have not put in place the technologies to automate DR both load shed within a facility and the startup of emergency generation (ConEd 2008). The value of DR and the design of DR programs should take into account system operations. Ten-minute notice DR can be valuable in helping defer some investment in T&D. While not all customers may choose to provide ten-minute notice response, there should be an increasing number of customers that will provide this type of response in the future and programs should be designed to acquire this resource. This type of DR is often a more valuable form of DR with higher savings for the utility, and utilities are often ready to pay up to twice as much to customers for this short-notice responsiveness.

<u>Industrial DR Potential in Virginia</u>
A similar analysis was conducted for the industrial sector: load shed participation rates and curtailment rates were applied to industrial peak demand. A previous study found industrial participation rates to vary from 25% for facilities <300kW, to 50% for >300kW (Summit Blue

2008a).For this study, the following rates were applied to participation: Low (20%); Medium (30%); and High (40%).

Previous studies have found industrial curtailment rates to vary from 17% (Quantec 2007), to 30% (Consortium 2004), to 75% (Nordham 2007), resulting in a mean of 41%. The following conservative rates were applied to curtailment for this study: Low (20%); Medium (30%); and High (40%). With these participation rates and potential load curtailments, the high load reduction potential for the overall industrial sector loads is 16% (i.e., 40% participation and 40% of that load participating).

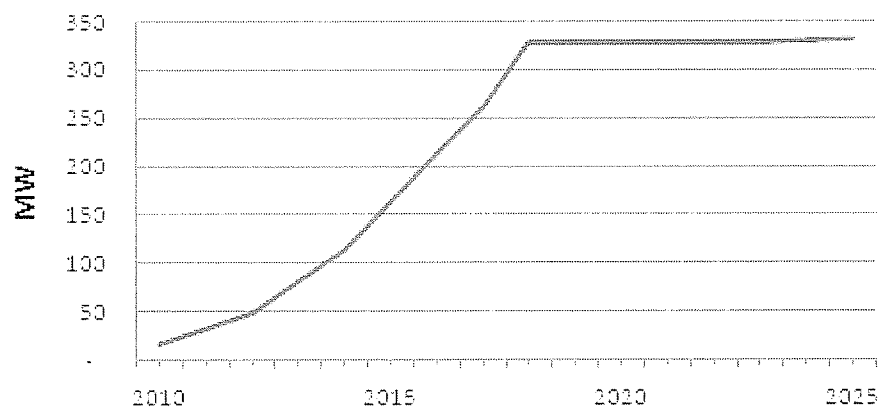
Table D-7 displays the input data and results. The medium scenario estimates 162 MW reduction of industrial peak demand possible by 2015, and 327 MW reduction of industrial peak demand possible by 2020. The low scenario estimates a 72 MW reduction by 2015 and a 145 MW reduction by 2020. The high scenario estimates a 289 MW reduction by 2015 and a 582 MW reduction by 2020.

Table D-7. Potential Industrial Load Shed in Virginia, in Years 2015 and 2020

INPUTS		
Industrial Peak Demand (MW)	3,636	
Load Participation Rate: Low	20%	
Load Participation Rate: Medium	30%	
Load Participation Rate: High	40%	
Curtailment Rate: Low	20%	
Curtailment Rate: Medium	30%	
Curtailment Rate: High	40%	
RESULTS	**2015**	**2020**
Industrial DR load reduction: Low (MW)	72	145
Industrial DR load reduction: Med (MW)	162	327
Industrial DR load reduction: High (MW)	289	582

Figure D-7 shows the resulting industrial load shed reductions possible for Virginia, from year 2010, when load reductions are expected to begin, through year 2025.

Figure D-7. Potential Industrial Load Shed in Virginia



The largest load reductions, and often the most cost-effective, may be found in Virginia's largest commercial and industrial customers. Data concerning these largest facilities were not available in Virginia so estimates are not quantified separately from the industrial analysis given in the previous section.

D.6.2. Commercial and Industrial Backup Generation Potential in VA

Emergency backup generation is a prominent component of a callable load program strategy. Some of the emergency generators not currently participating in DR programs may not be permitted for use as a DR resource and regulations may further limit the availability of emergency generation for DR. In some cases, backup generators may not be equipped with the start-up equipment to allow the generator to participate in short-term notification programs. Utilities could consider a program to assist customers with equipment specification and set-up to promote DR program participation by back-up generators.

In some instances, there may be environmental restrictions on emergency generation. Emissions of emergency generation may be regulated, and the future of such regulations may add some uncertainty. However, some areas have been able to have such restrictions lifted during system emergencies.

Two approaches can increase the amount of emergency generation in DR programs: 1) facilitating customer-owned generation, and 2) utility ownership of the generation, which is used to provide additional reliability for customers willing to locate the equipment at their facilities.

Customer-owned Emergency Generation
To increase customer-owned emergency generation, utilities may assist customers with ownership of grid-synchronized emergency generation. Utilities may offer to pay for all equipment necessary for parallel interconnection with the utility grid, as well as all maintenance and fuel expenses. Once operational, the standby generators can be monitored and dispatched from a utility's control center, and they can also provide backup power during an outage. An additional benefit to the customer relative to typical backup generation is the seamless transition to and from the generator without the usual momentary power interruption.

Utility-owned Emergency Generation
A second approach to increasing the availability of emergency generation for DR is by locating generation at customer sites that can be owned by a utility. Through this type of program, the customer receives emergency generation capability during system outages in exchange for paying a monthly fee consisting of both levelized capital costs and operation and maintenance costs. Participants would likely receive capacity payments ($/kW-month) and/or energy payments ($/kWh) in exchange for granting a utility to dispatch the units for a limited number of events and total hours per year.

Backup Generation in Virginia
A Distributed Energy Resources workshop, coordinated by the Alexandria Research Institute (ARI) and the Virginia State Corporation Commission, was held in May, 2002. The workshop identified the implications of distributed resources for the various major stakeholders and suggested a role for the Commonwealth in developing policies to promote, control or otherwise affect their development. The workshop concluded that distributed energy resources in Virginia offer a potential additional source of electrical energy supply over the next several years , with estimates ranging from 20% to 40% of installed capacity available from central power stations (CIMAP 2002).

Total Virginia back-up generation capacity for 2008 is estimated at approximately 1.79 GW.[9] Additional analysis revealed that the commercial back-up capacity is almost half of the total capacity, 896 MW.[10] Assuming a medium scenario that 40% of the total backup in Virginia is available for load

[9] Back-up generation capacity in Virginia was estimated from form EIA-861 filings submitted by utilities nationwide (EIA, 2006). However, only utilities providing approximately one-quarter of total kWh report these numbers. It was assumed that the prevalence and usage of distributed generation in the remaining 75% of utilities is similar.

[10] The analysis first determined the back-up generator population nation-wide, and then scaled the data down to the South Atlantic region (CBECS resolution), accounting for proportional differences in building stock nation-

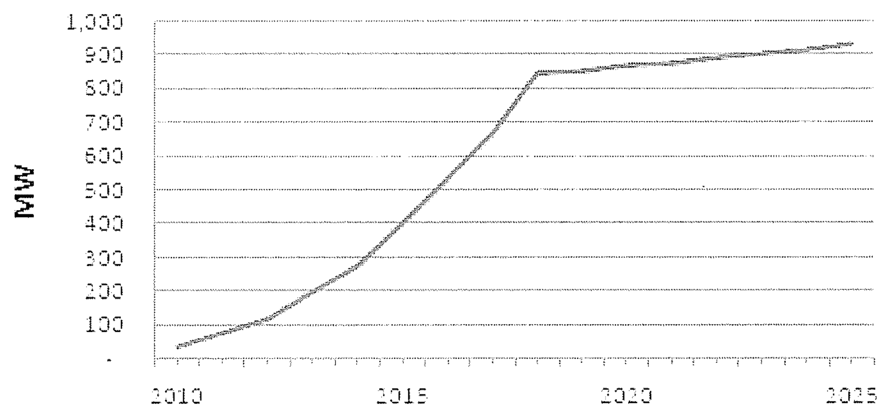
shed, then 402 MW of backup generation is available by 2015 and a 865 MW of backup generation is available by 2020 (see Table D-8). The low scenario estimates a 302 MW reduction by 2015 and a 649 MW reduction by 2020. The high scenario estimates a 503 MW reduction by 2015 and a 1,082 MW reduction by 2020.

Table D-8. Potential Reductions from C&I Backup Generation in Virginia, in Years 2015 and 2020[a]

INPUTS		
Total Backup Generation Capacity in VA (MW)	2,163	
Backup Generation Potential (%): Low	30%	
Backup Generation Potential (%): Medium	40%	
Backup Generation Potential (%): High	50%	
RESULTS	**2015**	**2020**
Potential Reduction from C&I Backup Generation (MW): Low	302	649
Potential Reduction from C&I Backup Generation (MW): Medium	402	865
Potential Reduction from C&I Backup Generation (MW): High	503	1,082

Figure D-8 shows the resulting commercial and industrial backup generation reductions possible for Virginia, from year 2010, when load reductions are expected to begin, through year 2025.

Figure D-8. Potential Reductions from C&I Backup Generation



D.6.3. Pricing and Rates

In this assessment of DR potential, the focus is on the use of direct load control and curtailable load response programs callable by the utility. Studies have shown that pricing programs, specifically dispatchable pricing programs such as critical peak pricing (CPP) programs can provide similar impacts; however, for the purposes of this assessment, a focus on the these load response programs is believed to be able to fully represent the DR potential, even though pricing programs could be used instead of these curtailable load programs with equal, or in some cases, greater efficiency.

New rates may be introduced as part of a DR program, and may include real-time prices, or other time-differentiated rates, for commercial and industrial customers, and a modification of any existing

wide and region-wide. The region-wide results were then scaled down to Virginia specifically using the ratio of Virginia population to regional population.

residential time-of-use (TOU) rates. Any new rate structures would be designed to reduce system demand during peak periods and provide an opportunity for customers to reduce electric bills through load shifting.

Critical peak pricing (CPP) is a viable option for inclusion in a DR portfolio. In FERC's 2006 survey of utilities offering DR programs (citation below), roughly 25 entities reported offering at least one CPP tariff. However, many of the tariffs were pilot programs only, and almost all of the 11,000 participants were residential customers. The apparent lack of commercial CPP programs is supported by a 2006 survey of pricing and DR programs commissioned by the U.S. EPA (below), which found only four large-customer CPP programs, all of them in California. The pilot programs in California linked the CPP rate with "automated demand response" technologies that provide most of the impact. The CPP rate itself, and the price incentive that it creates, is not the driver behind the load reductions.

As stated, rate pricing options were not analyzed in this analysis. Event-based pricing programs achieve impacts very similar to the callable load programs presented above. Pilot studies and tariff evaluations of TOU-CPP programs[11] show the load reductions for called events are similar in magnitude to air conditioning DLC programs. This is not surprising in that most TOU-CPP participants use a programmable-automated thermostat to respond to CPP events in a manner similar to a DLC strategy. One difference is that the customer response is less under the control of the program or system operator that could change cycling strategies or thermostat set points across different events or different hours within an event. Similarly, demand-bid programs are simply calls for target load sheds, i.e., those bid into the program.

In general, the direct load shed programs seem to provide greater MW of participation and more reliable reductions. However, the use of either TOU-CPP or a demand-bid program represents a point of view or policy position that price should be a centerpiece of the DR effort and help customers see prices in the electricity markets. From a point of view of simplicity and attaining firm capacity reductions, the direct load shed programs may offer some advantages. Ultimately, the choice between these direct load shed programs and pricing programs may come down to customer preferences and decisions by policy makers on the emphasis of DR efforts.

A time-differentiated rate is another option to consider that may not be "callable." Such rates include day-ahead real-time pricing (RTP), two-part RTP tariffs, and standard TOU rates. Although they are not "callable" in that the rate is generally in effect every day, there may be synergies between time-differentiated rates and callable load programs. In general, an RTP option will result in customers learning how to reduce energy consumption on essentially a daily basis when prices tend to be high (e.g., summer season afternoons and early evenings). Customers do not tend to track exact hourly prices, but they know when prices are likely to be higher (e.g., summer season afternoons with higher prices on hot days).[12] The benefits to the customer come from reducing consumption across many summer days when prices are high, rather than a focus on reduction during system event days. In general, the reductions on system peak days are roughly the same as on any summer day when prices are reasonably high. As a result, an RTP option can provide substantial benefits by increasing overall market and system efficiency through shifting loads from high priced periods to periods with lower prices. However, these tariffs may not provide the needed load relief on system-constrained event days.[13, 14]

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[11] See Public Service Electric and Gas Company, "Evaluation of the MyPower Pricing Pilot Program," prepared by Summit Blue Consulting, 2007; and the California Energy Commission, "Impact evaluation of the California Statewide Pricing Pilot—Final Report," March 16, 2005. Web reference: http://www.energy.ca.gov/demandresponse/documents/index.html#group3.

[12] See evaluations of the hourly pricing experiment offered by ComEd and the Chicago Energy Cooperative performed by Summit Blue Consulting (2003 through 2006).

[13] One way to make an RTP tariff more like an event-based DR program is to overlay a critical peak pricing (CPP) component on the RTP tariff where unusually high prices would be posted to customers with some notification period. Otherwise, it is unlikely that the high levels of reduction needed for system-event days would be attained.

D.7.Summary of DR Potential Estimates in Virginia

Table D-9 shows the resulting load shed reductions possible for Virginia, by sector, for years 2015, 2020, and 2025. The high scenario DR load potential reduction is within a range of reasonable outcomes in that it has an eleven year rollout period (beginning of 2010 through the end of 2020), providing a relatively long period of time to ramp up and integrate new technologies that support DR. A value nearer to the high scenario than the medium scenario would make a good MW target for a set of DR activities. The high scenario results show a reduction in peak demand of 1,566 MW (5.4% of 2015 peak demand) is possible by 2015; 3,332 MW (10.8% of 2020 peak demand) is possible by 2020; and 3,537 MW (10.8% of 2025 peak demand) is possible by 2025. The more conservative medium scenario results show a reduction in peak demand of 1,038 MW (3.6% of 2015 peak demand) is possible by 2015; 2,209 MW (7.2% of 2020 peak demand) is possible by 2020; and 2,345 MW (7.2% of 2025 peak demand) is possible by 2025. Load impacts grow rapidly through 2018 as program implementation takes hold. After 2018, the program impacts increase at the same rate as the forecasted growth in peak demand.

These estimated reductions in peak demand are within a range to be expected for a population of Virginia's size. Estimates of DR in other states show that the estimates calculated here for Virginia are conservative: 15% reductions in peak demand in Florida are possible by 2023 (Elliot et al. 2007a), and 13% are possible in Texas, also by year 2023 (Elliot et al. 2007b). DR potential for a utility in New York was estimated to be 9.3% of peak demand in 2017 (Summit Blue 2008a). This finding is similar to that of a recent analysis estimating that peak load reductions from DR in the Northeast will be 8.2% of system peak load in 2020 and more than 11% by 2030 (EPRI and EEI 2008). Estimation methods differ among the studies, but nonetheless show that the 8% reductions in Virginia are realistic for the medium scenario, and the high scenario estimates for approximately 12% are achievable as well. A previous study on DR in Virginia contains similar results, revealing that 8.8% reductions in peak demand are possible by 2017 through DR programs (Summit Blue 2007c). The small difference in the estimated potential is attributable to different estimation methods and slightly varying inputs including participation rates, residential load reductions, and target years for full participation rates. In addition, the 2007 study included quantified estimates for reductions through pricing programs, in addition to direct load control reductions.

[14] The complementary of event-based load shed programs with RTP tariffs is assessed in: Violette, D., R. Freeman, and C. Neil. *DR Valuation and Market Analysis—Volume II: Assessing the DR Benefits and Costs*, Prepared for the International Energy Agency, TASK XIII, Demand-Side Programme, Demand Response Resources, January 6, 2006. Updated results are presented in: Violette, D. and R. Freeman; "Integrating Demand Side Resource Evaluations in Resource Planning;" *Proceedings of the International Energy Program Evaluation Conference (IEPEC)*, Chicago, August 2007 (also at www.IEPEC.com).

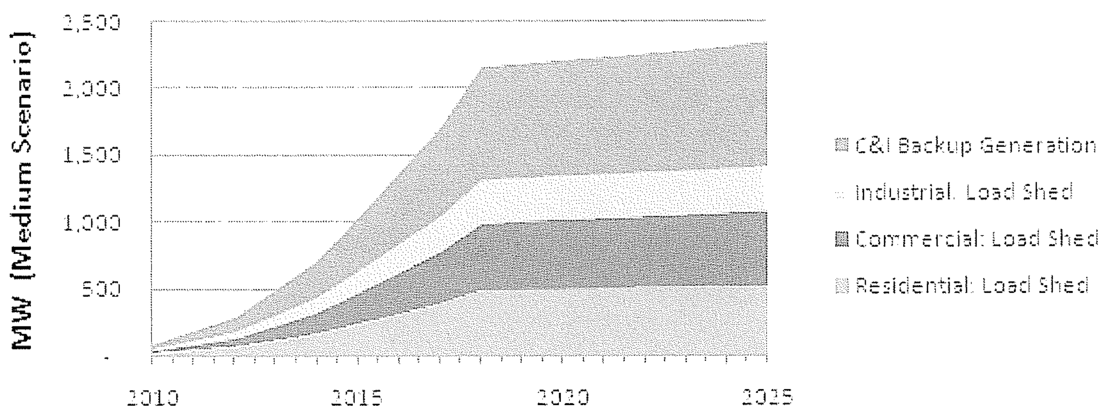
Table D-9. Summary of Potential DR in Virginia, By Sector, for Years 2015, 2020, and 2025[a]

	Low Scenario			Medium Scenario			High Scenario		
	2015	**2020**	**2025**	**2015**	**2020**	**2025**	**2015**	**2020**	**2025**
Residential: Load Shed (MW)	143	299	310	238	499	516	333	699	723
Commercial: Load Shed (MW)	88	194	213	235	517	567	441	970	1,063
Industrial: Load Shed (MW)	72	145	147	162	327	331	289	582	588
C&I Backup Generation (MW)	302	639	698	402	865	930	503	1,082	1,163
Total DR Potential (MW)	605	1,288	1,367	1,038	2,209	2,345	1,566	3,332	3,537
DR Potential as % of Total Peak Demand (30,065 MW)	2.1%	4.2%	4.2%	3.6%	7.2%	7.2%	5.4%	10.8%	10.8%

a. See Section 3 for underlying data and assumptions.

Figure D-9 shows the resulting load shed reductions possible for Virginia, by sector, from year 2010, when load reductions are expected to begin, through year 2025.

Figure D-9. Potential DR Load Reductions in Virginia by Sector (MW)



These estimates reflect the level of effort put forth and utilities are recommended to set targets for the high scenarios. These estimates include assumptions based on utility experience regarding growth rates, participation rates, and program design, among others, and will adjust accordingly if differing assumptions are made. The assumptions made are believed to be conservative, and reflect minimum achievable DR potential. For example, participation rates for all of the sectors are based on experience in other states, and are based primarily on customer awareness, the ability to have automated response, and the adequacy of reward. If the statewide education program now required in Virginia promotes DR programs and adequate incentives are offered, then participation rates higher than the medium scenario are entirely realistic.

D.8.Recommendations

This assessment indicates that the system peak demand can be reduced by approximately 7.8% or 2,209 MW in 2020 in the medium case. In the high case, the reduction can be as high as 11.7% or 3332 MW. The high case is considered to be within a reasonable range if aggressive action begins by the end of 2009, providing for a twelve-year rollout of the DR efforts (at the beginning of 2010 through the end of 2020). Key recommendations include:

- Appropriate financial incentives for the Virginia' utilities either for programs administered directly by the utilities or for outsourcing DR efforts to aggregators. The basic premise is that a utility's least-cost plan should also be its most profitable plan. Developing these incentives poses some complexities in that MW's in that DR programs likely will be bid into PJM's DR programs and will receive financial payments from PJM. Whether this provides adequate incentives for the appropriate development of DR programs in Virginia should be examined.

- It is important that the DR programs be integrated with the delivery of EE programs. Many gains in delivery efficiency are possible by combining and cross-marketing EE and DR programs. These can include new building codes and standards that include not only energy efficiency construction and equipment, but also the installation of addressable and dispatchable equipment. This can include addressable thermostats in new residences and the installation of addressable energy management systems in commercial and industrial buildings that can reduce loads in select end-uses across the building/facility. In addition, energy audits of residential or commercial facilities can also include an assessment of whether that facility is a good candidate for participation in a DR program through the identification of dispatchable loads. Furthermore, building commissioning and retro-commissioning EE programs that are becoming popular in many commercial and industrial sector programs have the energy management system as a core component of program delivery. At this time, the application of auto-DR can be assessed and marketed to the customer along with the EE savings from these site-commissioning programs.

- Implement programs focused on achieving firm capacity reductions as this provides the highest value demand response. This is accomplished through establishing appropriate customer expectations and by conducting program tests for each DR program in each year. These tests should be used to establish expected DR program impacts when called and to work with customers each year to ensure that they can achieve the load reductions expected at each site.

- Plan for at-scale programs through the rollout period. Pilot programs can be important in determining the appropriate design of cost-effective DR programs. However, there are established DR programs and technologies. Even with the unique circumstances in Virginia, these programs can be designed for deployment at scale. However, this approach recognizes that the first year of program deployment and possibly the second year should be designed to test key design components as part of a program shakeout. The third year of a program that should represent an efficient design and an at-scale program. DSM programs are designed to be flexible and undergo year-to-year changes due to market, customer and technology factors. This will always be the case and the benefits of discrete pilot program can limit overall program participation for a number of years resulting in "lost DR MWs." The politics of DSM and diverse positions of parties can result in a compromise in the implementation of programs leading to a two to three-year pilot program. This can delay the delivery of DR at scale resulting in higher overall costs. The over-use of pilots that do not acknowledge the ability of a program roll-out to have at-scale deliver as its goal in year three, but to also have tests of design components and decision nodes built into the first two year of program rollout can result in "death by piloting" for attainable DR MWs. Also, a decision to run a pilot program must be based on the assumption that the program will not have enough flexibility in design and on-going decision nodes during the first two years to allow for the ramp up into full scale efficient deployment in year three.

- Load reduction programs typically have less need for pilot programs as the reductions are defined by the equipment and processes outlined by the program for each participant. Time differentiated pricing is a cornerstone of efficient electric markets and the design of these programs may need more pilot testing as the customer response to pricing is voluntary and not set (as often) by program design.

- Virginia has a history of time-differentiated rates. Pricing should form the cornerstone of an efficient electric market. Daily TOU pricing and day-ahead hourly pricing will increase overall market efficiency by causing shifts in energy use from on-peak to off-peak hours every day of the year. However, this does not diminish the need to have dispatchable DR programs that can address those few days that represent extreme events where the highest demands occur. These events are best addressed by dispatchable DR programs.

- Key programs that be considered for roll-out and can be designed within a 12-month period include:
  - Residential and small business AC direct load control using switches or thermostats (or giving customers their choice of technology).[15]
  - Auto-DR programs providing direct load curtailment for larger commercial and industrial customers.
  - Callable interruptible programs with manual response to an event notification for larger commercial and industrial customers where auto-DR approaches are not acceptable to the customer or technically not feasible.
  - Aggressive enrollment of back-up generators in DR programs.

- Customer education should be included in DR efforts (as also recommended by the SCC Sub-group 3 (SCC 2007). There is some perceived lack of customer awareness of programs and incentives. In addition, new programs will need marketing efforts as well as technical assistance to help customers identify where load reductions can be obtained and the technologies/actions needed to achieve these load reductions. Also, high-level education on the volatility of electricity markets helps customers understand why utilities and other entities are promoting DR and the customers' role in increasing demand response to help match up with supply-side resources to achieve lower cost resource solutions when markets become tight

- Increase clarity and coordination between the Federal and State agencies and programs (as also recommended by the SCC Sub-group 3 (SCC 2007). While states have primary jurisdiction over retail demand response, the FERC has jurisdiction over demand response in wholesale markets. Greater clarity and coordination between the Federal and State programs is needed.

[15] This approach is currently being used successfully by LGE Energy.

Appendix E - Combined Heat and Power

E.1.Technical Potential for CHP

This section provides an estimate of the technical market potential for combined heat and power (CHP) in the industrial, commercial/institutional, and multi-family residential market sectors. Two different types of CHP markets were included in the evaluation of technical potential. Both of these markets were evaluated for high load factor (80% and above) and low load factor (51%) applications resulting in four distinct market segments that are analyzed.

E.1.1. Traditional CHP

Traditional CHP electrical output is produced to meet all or a portion of the base load for a facility and the thermal energy is used to provide steam or hot water. Depending on the type of facility, the appropriate sizing could be either electric or thermal limited. Industrial facilities often have "excess" thermal load compared to their on-site electric load. Commercial facilities almost always have excess electric load compared to their thermal load. Two sub-categories were considered:

High load factor applications: This market provides for continuous or nearly continuous operation. It includes all industrial applications and round-the-clock commercial/institutional operations such colleges, hospitals, hotels, and prisons.

Low load factor applications: Some commercial and institutional markets provide an opportunity for coincident electric/thermal loads for a period of 3,500 to 5,000 hours per year. This sector includes applications such as office buildings, schools, and laundries.

E.1.2. Combined Cooling Heating and Power (CCHP)

All or a portion of the thermal output of a CHP system can be converted to air conditioning or refrigeration with the addition of a thermally activated cooling system. This type of system can potentially open up the benefits of CHP to facilities that do not have the year-round thermal load to support a traditional CHP system. A typical system would provide the annual hot water load, a portion of the space heating load in the winter months and a portion of the cooling load in during the summer months. Two sub-categories were considered:

Low load factor applications. These represent markets that otherwise could not support CHP due to a lack of thermal load.

Incremental high load factor applications: These markets represent round-the-clock commercial/institutional facilities that could support traditional CHP, but with cooling, incremental capacity could be added while maintaining a high level of utilization of the thermal energy from the CHP system. All of the market segments in this category are also included in the high load factor traditional market segment, so only the incremental capacity for these markets is added to the overall totals.

The estimation of technical market potential consists of the following elements:

- Identification of applications where CHP provides a reasonable fit to the electric and thermal needs of the user. Target applications were identified based on reviewing the electric and thermal energy consumption data for various building types and industrial facilities.
- Quantification of the number and size distribution of target applications. Several data sources were used to identify the number of applications by sector that meet the thermal and electric load requirements for CHP.

- Estimation of CHP potential in terms of megawatt (MW) capacity. Total CHP potential is then derived for each target application based on the number of target facilities in each size category and sizing criteria appropriate for each sector.
- Subtraction of existing CHP from the identified sites to determine the remaining technical market potential.

The technical market potential does not consider screening for economic rate of return, or other factors such as ability to retrofit, owner interest in applying CHP, capital availability, natural gas availability, and variation of energy consumption within customer application/size class. The technical potential as outlined is useful in understanding the potential size and size distribution of the target CHP markets in the state. Identifying technical market potential is a preliminary step in the assessment of market penetration.

The basic approach to developing the technical potential is described below:

- *Identify existing CHP in the state.* The analysis of CHP potential starts with the identification of existing CHP. In Virginia, there are 9 operating CHP plants totaling 322 MW of capacity. This existing CHP capacity is deducted from any identified technical potential.

- *Identify applications where CHP provides a reasonable fit to the electric and thermal needs of the user.* Target applications were identified based on reviewing the electric and thermal energy (heating and cooling) consumption data for various building types and industrial facilities. Data sources include the DOE EIA *Commercial Buildings Energy Consumption Survey (CBECS),* the DOE *Manufacturing Energy Consumption Survey (MECS)* and various market summaries developed by DOE, Gas Technology Institute (GRI), and the American Gas Association. Existing CHP installations in the commercial/institutional and industrial sectors were also reviewed to understand the required profile for CHP applications and to identify target applications.

- *Quantify the number and size distribution of target applications.* Once applications that could technically support CHP were identified, the iMarket, Inc. *MarketPlace Database* and the *Major Industrial Plant Database* (MIPD) from IHI were utilized to identify potential CHP sites by SIC code or application, and location (county). The *MarketPlace Database* is based on the Dun and Bradstreet financial listings and includes information on economic activity (8 digit SIC), location (metropolitan area, county, electric utility service area, state) and size (employees) for commercial, institutional and industrial facilities. In addition, for select SICs limited energy consumption information (electric and gas consumption, electric and gas expenditures) is provided based on data from Wharton Econometric Forecasting (WEFA). MIPD has detailed energy and process data for 16,000 of the largest energy consuming industrial plants in the United States. The *MarketPlace Database* and MIPD were used to identify the number of facilities in target CHP applications and to group them into size categories based on average electric demand in kiloWatt-hours.

- *Estimate CHP potential in terms of MW capacity.* Total CHP potential was then derived for each target application based on the number of target facilities in each size category. It was assumed that the CHP system would be sized to meet the average site electric demand for the target applications unless thermal loads (heating and cooling) limited electric capacity. Tables E-1 through E-3 present the specific target market sectors, the number of potential sites and the potential MW contribution from CHP. There are two distinct applications and two levels of annual load making for four market segments in all. In traditional CHP, the thermal energy is recovered and used for heating, process steam, or hot water. In cooling CHP, the system provides both heating and cooling needs for the facility. High load factor applications operate at 80% load factor and above; low load factor applications operate at an assumed average of 4500 hours per year (51%) load factor. The high load factor cooling applications are also applications for traditional CHP, though the cooling applications have

25-30% more capacity than traditional. Therefore, the totals for the entire state, all four market segments, discounts these applications to avoid double counting.

- *Estimate the growth of new facilities in the target market sectors.* The technical potential included economic projections for growth through 2025 by target market sectors in Virginia. The growth factors used in the analysis for growth between the present and 2025 by individual sector are shown in Table E-4. These growth projections provided by ACEEE were used in this analysis as an estimate of the growth in new facilities. In cases where an economic sector is declining, it was assumed that no new facilities would be added to the technical potential for CHP. Based on these growth rates the total technical market potential is summarized in Table E-5.

Table E-1. Virginia Technical Market Potential for CHP in Existing Facilities—Industrial Sector

SICs	Application	50-500 kW Sites	50-500 kW MW	500-1 MW Sites	500-1 MW (MW)	1-5 MW Sites	1-5 MW (MW)	5-20 MW Sites	5-20 MW (MW)	>20 MW Sites	>20 MW (MW)	Total Sites	Total MW
Industrial (Traditional, High Load Factor													
20	Food	140	21.0	30	22.5	27	67.5	7	89.8	1	44.5	205	245.3
21	Tobacco Manufacturers							1	5.6	0			5.6
22	Textiles	50	5.6	22	12.4	13	24.4	1	15.4	4	334.1	90	391.9
24	Lumber and Wood	207	6.2	53	8.0	14	7.0	2	22.3	1	59.1	277	102.5
25	Furniture	19	0.9	12	2.7	0	0.0	4	50.2	0		35	53.8
26	Paper	44	6.6	23	17.3	44	110.0	1	15.7	19	1,441.0	131	1,590.5
27	Printing/Publishing	76	11.4	7	5.3	0	0.0	1	5.5	0		84	22.1
28	Chemicals	63	9.5	20	15.0	28	70.0	2	23.3	6	441.6	119	559.4
29	Petroleum Refining	26	3.9	2	1.5	0	0.0	0	0.0	1	54.2	29	59.6
30	Rubber/Misc Plastics	58	2.6	34	7.7	37	27.8	2	19.0	1	67.8	132	124.7
32	Stone/Clay/Glass	4	0.6	8	6.0	0	0.0	1	11.0	0	0.0	13	17.6
33	Primary Metals	11	0.4	4	0.8	4	2.5	0	0.0	0	0.0	19	3.7
34	Fabricated Metals	28	1.3	4	0.9	3	2.3	0	0.0	1	82.4	36	86.8
35	Machinery/Computer Equip	10	0.4	4	0.8	0	0.0	1	11.0	0	0.0	15	12.1
37	Trasportation Equip.	46	3.5	20	7.5	25	31.3	2	23.0	1	82.4	94	147.6
38	Instruments	14	1.1	2	0.8	2	2.5	1	5.0	0	0.0	19	9.3
39	Misc Manufacturing	7	0.3	3	0.6	0	0.0	0	0.0	0	0.0	10	0.8
	Total	803	75.1	248	109.4	197	345.1	26	296.7	35	2607.1	1308	3433.3

Table E-2. Virginia Technical Market Potential for CHP in Existing Facilities—Commercial, Traditional CHP

SICs	Application	50-500 kW Sites	50-500 kW MW	500-1 MW Sites	500-1 MW (MW)	1-5 MW Sites	1-5 MW (MW)	5-20 MW Sites	5-20 MW (MW)	>20 MW Sites	>20 MW (MW)	Total Sites	Total MW
Commercial, Multifamily(Traditional, High Load Factor)													
6513	Apartments	249	18.7	90	33.8	14	17.5		0.0		0.0	353	69.9
4222, 5142	Warehouses	16	2.4	13	9.8	1	2.5		0.0		0.0	30	14.7
4941, 4952	Water Treatment/Sanitary	21	3.2	22	16.5	20	50.0	2	25.0		0.0	65	94.7
7011, 7041	Hotels	839	94.4	146	82.1	58	108.8	2	18.8		0.0	1045	304.0
8051, 8052, 8059	Nursing Homes	222	33.3	116	87.0	13	32.5		0.0		0.0	351	152.8
8062, 8063, 8069	Hospitals	65	9.8	34	25.5	77	192.5	1	12.5		0.0	177	240.3
8221, 8222	Colleges/Universities	95	14.3	75	56.3	35	87.5	7	87.5	1	25.0	213	270.5
9223, 9211 (Courts), 9224 (firehouses)	Prisons	17	2.6	54	40.5	45	112.5	1	12.5		0.0	117	168.1
	Total C/I High LF	1524	178.5	550	351.4	263	603.8	13	156.3	1	25	2351	1314.8
Commercial (Traditional, Low Load Factor)													
7542	Carwashes	54	8.1		0.0		0.0		0.0		0.0	54	8.10
8412	Museums	68	10.2	6	4.5		0.0		0.0		0.0	74	14.70
7211, 7213, 7218	Laundries	44	6.6	3	2.3		0.0		0.0		0.0	47	8.85
7991, 00, 01	Health Clubs	133	20.0	14	10.5		0.0		0.0		0.0	147	30.45
7992, 7997-9904, 7997-9906	Golf/Country Clubs	174	26.1	14	10.5		0.0		0.0		0.0	188	36.60
8211, 8243, 8249, 8299	Schools	813	30.5	155	29.1	11	6.9		0.0		0.0	979	66.43
	Total C/I Low LF	1286	101.4	192	56.813	11	6.875	0	0	0	0	1489	165.13
	Total C/I Traditional	2810	279.9	742	408.19	274	610.625	13	156.3	1	25	3840	1480.0

Table E-3. Virginia Technical Market Potential for CHP in Existing Facilities—Commercial, Cooling

SICs	Application	50-500 kW Sites	50-500 kW MW	500-1 MW Sites	500-1 MW (MW)	1-5 MW Sites	1-5 MW (MW)	5-20 MW Sites	5-20 MW (MW)	>20 MW Sites	>20 MW (MW)	Total Sites	Total MW
Commercial Cooling, High Load Factor													
7011, 7041	Hotels- Cooling	839	125.9	146	109.5	58	145.0	2	25.0			1045	405.4
8051, 8052, 8059	Nursing Homes- Cooling	222	40.0	116	104.4	13	39.0		0.0			351	183.4
8062, 8063, 8069	Hospitals- Cooling	66	11.9	34	30.6	78	234.0	1	15.0			179	291.5
	Total Cooling High LF	1127	177.7	296	244.5	149	418	3	40			1575	880.2
Commercial Cooling, Low Load Factor													
43	Post Offices	60	9.0		0.0		0.0					60	9.0
4581	Airports	12	1.8		0.0		0.0					12	1.8
6512	Office Buildings - Cooling	1408	105.6	563	211.1	141	176.3					2112	493.0
7832	Movie Theaters	53	8.0		0.0		0.0					53	8.0
52,53,56,57	Big Box Retail	799	119.9	177	132.8	56	140.0					1032	392.6
5411, 5421, 5451, 5461, 5499	Food Sales	1097	82.3	132	49.5	13	16.3					1242	148.0
5812, 00, 01, 03, 05, 07, 08	Restaurants	1130	84.8	9	3.4		0.0					1139	88.1
	Total Cooling Low LF	4559	411.2	881	396.75	210	332.5	0	0	0	0	5650	1140.48
	Total Cooling	5686	588.9	1177	641.25	359	750.5	3	40	0	0	7225	2020.7
	Total C/I All Types	8496	868.8	1919	1049.4	633	1361.13	16	196.3	1	25	11065	3500.6

Table E-4. Virginia Sector Growth Projections Through 2025

SIC Code	Market Sector	2008-2025 Real Growth
20	Food	10.4%
22	Textiles	0.0%
24	Lumber and Wood	10.2%
25	Furniture	10.2%
26	Paper	10.2%
27	Printing/Publishing	0.0%
28	Chemicals	69.5%
29	Petroleum Refining	69.5%
30	Rubber/Misc Plastics	69.5%
32	Stone/Clay/Glass	31.9%
33	Primary Metals	30.3%
34	Fabricated Metals	30.3%
35	Machinery/Computer Equip	63.9%
37	Trasportation Equip.	31.7%
38	Instruments	48.8%
39	Misc Manufacturing	10.2%
4222, 5142	Warehouses	0.0%
4941, 4952	Water Treatment/Sanitary	50.6%
5411, 5421, 5451, 5461, 5499	Food Sales	91.9%
5812, 00, 01, 03, 05, 07, 08	Restaurants	60.5%
7011, 7041	Hotels	60.5%
7211, 7213, 7218	Laundries	11.3%
7542	Carwashes	11.3%
7991, 00, 01	Health Clubs	60.5%
7992, 7997-9904, 7997-9906	Golf/Country Clubs	60.5%
8051, 8052, 8059	Nursing Homes	32.8%
8062, 8063, 8069	Hospitals	32.8%
8211, 8243, 8249, 8299	Schools	32.8%
8221, 8222	Colleges/Universities	32.8%
8412	Museums	60.5%
9223, 9211 (Courts), 9224 (firehouses)	Prisons	13.2%
6513	Apartments	0.0%
43	Post Offices	44.7%
4581	Airports	44.7%
52,53,56,57	Big Box Retail	91.9%
7832	Movie Theaters	60.5%
7011, 7041	Hotels- Cooling	60.5%
8051, 8052, 8059	Nursing Homes- Cooling	32.8%
8062, 8063, 8069	Hospitals- Cooling	32.8%
6512	Office Buildings - Cooling	0.0%

Table E-5. CHP Market Segments, Virginia Existing Facilities and Expected Growth 2007-2020

Market	50-500 kW MW	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total MW
Traditional High Load Factor Market						
Existing Facilities	254	461	949	453	2,632	4,748
New Facilities	82	126	267	140	501	1,116
Total	335	587	1,216	593	3,133	5,864
Traditional Low Load Factor Market						
Existing Facilities	101	57	7	0	0	165
New Facilities	39	21	2	0	0	62
Total	141	78	9	0	0	227
Cooling CHP High Load Factor Market (partially additive)						
Existing Facilities	178	245	418	40	0	880
New Facilities	80	96	153	13	0	341
Total	258	340	571	53	0	1,221
Cooling CHP Low Load Factor Market						
Existing Facilities	411	397	333	0	0	1,140
New Facilities	209	144	123	0	0	476
Total	621	541	455	0	0	1,616
Total Market including Incremental Cooling Load						
Existing Facilities	819	988	1,414	465	2,632	6,318
New Facilities	354	320	437	144	501	1,756
Total	1,173	1,308	1,851	608	3,133	8,074

Note: High load factor cooling market is comprised of a portion of the traditional high load factor market that has both heating and cooling loads. The total high load factor cooling market is shown, but only 30% of it is incremental to the portion already counted in the traditional high load factor market. Growth rates were extrapolated for the 2020-2025 market penetration forecast.

E.2.Energy Price Projections

The expected future relationship between purchased natural gas and electricity prices, called the *spark spread* in this context, is one major determinant of the ability of a facility with electric and thermal energy requirements to cost-effectively utilize CHP. For this screening analysis, a fairly simple methodology was used:

E.2.1. Electric Price Estimation

- Retail electric price forecasts based on were used as the starting point for the analysis. ACEEE provided state by state estimates. The annual price forecasts provided were converted to 5 year averages for use in the market penetration model. These prices are shown in **Table E-6**.
- The electricity price assumptions for the high load factor CHP applications were as follows
  - 50-500 kW—Commercial average price
  - 500 kW to 5 MW—Industrial average price
  - 5 MW and above—90% of industrial average price
- Price adjustments for customer load factor were defined as follows:

  - High load factor—100% of the estimated value
  - Low load factor—120% of the estimated value
  - Peak cooling load—150% of the estimated value
- For a customer generating a portion of his own power with CHP, standby charges are estimated at 15% of the defined average electric rate. Therefore, when considering CHP, only 85% of a customer's rate can be avoided.

E.2.2. Natural Gas Price Estimation

- The natural gas price assumptions are based on the industrial retail price shown in the table.
  - All customer boiler fuel is assumed at the industrial rate except for the CHP market below 500 kW where the boiler gas price is assumed to be $0.50/MMBtu higher
  - All CHP fuel is assumed to be at a $0.60/MMBt discount to the retail industrial price.

Table E-6. Input Price Forecast (EIA-AEO 2007) and Virginia Industrial Electric Price Estimation[1]

Virginia Energy Prices	Avg. 2007-2009	Avg.2010-2014	Avg.2015-2019	Avg.2020-2024
Virginia Retail Electricity Prices (2006$/kWh)				
Residential	$ 0.104	$ 0.135	$ 0.151	$ 0.158
Commercial	$ 0.080	$ 0.101	$ 0.115	$ 0.121
Industrial	$ 0.065	$ 0.071	$ 0.077	$ 0.082
All Sector Avg.	$ 0.087	$ 0.108	$ 0.121	$ 0.127
Virginia Retail Natural Gas Prices (2006$/MMbtu)				
Residential	$15.456	$14.107	$14.390	$14.930
Commercial	$11.785	$10.400	$10.516	$10.870
Industrial	$9.303	$7.782	$7.923	$8.312

[1] These price vary somewhat from the reference forecast because the CHP analysis was undertaken before the final price forecasts were finalized.

E.3.CHP Technology Cost and Performance

The CHP system itself is the engine that drives the economic savings. The cost and performance characteristics of CHP systems determine the economics of meeting the site's electric and thermal loads. A representative sample of commercially and emerging CHP systems was selected to profile performance and cost characteristics in combined heat and power (CHP) applications. The selected systems range in capacity from approximately 100–20,000 kW. The technologies include gas-fired reciprocating engines, gas turbines, microturbines and fuel cells. The appropriate technologies were allowed to compete for market share in the penetration model. In the smaller market sizes, reciprocating engines competed with microturbines and fuel cells. In intermediate sizes (1 to 20 MW), reciprocating engines competed with gas turbines.

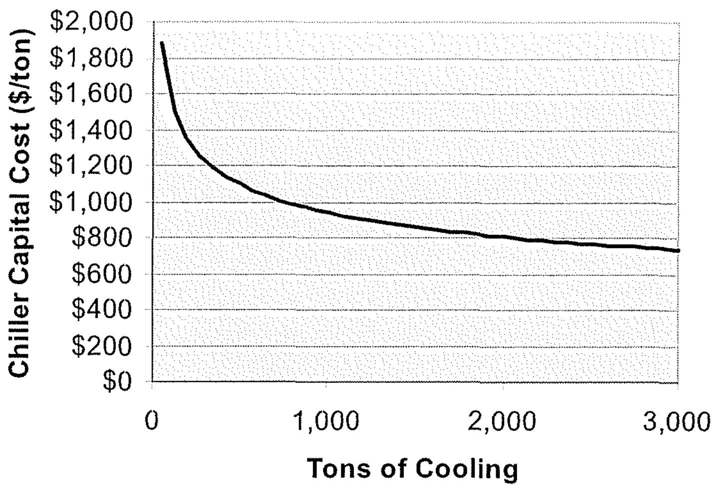
Cost and performance estimates for the CHP systems were based on work being undertaken for the EPA.[16] The foundation for these updates is based on work previously conducted for NYSERDA[17], on peer-reviewed technology characterizations that Energy and Environmental Analysis (EEA) developed for the National Renewable Energy Laboratory[18] and on follow-on work conducted by DE Solutions for Oak Ridge National Laboratory.[19] Additional emissions characteristics and cost and

[16] EPA CHP Partnership Program, Technology Characterizations, December 2007 (under review).
[17] *Combined Heat and Power Potential for New York State*, Energy Nexus Group (later became part of EEA), for NYSERDA, May 2002.
[18] "Gas-Fired Distributed Energy Resource Technology Characterizations", NREL, November 2003, http://www.osti.gov/bridge
[19] "Clean Distributed Generation Performance and Cost Analysis", DE Solutions for ORNL. April 2004.

performance estimates for emissions control technologies were based on ongoing work EEA is conducting for EPRI.[20] Data is presented for a range of sizes that include basic electrical performance characteristics, CHP performance characteristics (power to heat ratio), equipment cost estimates, maintenance cost estimates, emission profiles with and without after-treatment control, and emissions control cost estimates. The technology characteristics are presented for three years: 2005, 2010, 2020. The 2007-2010 estimates are based on current commercially available and emerging technologies. The cost and performance estimates for 2010-2015 and 2015-2020 reflect current technology development paths and currently planned government and industry funding. These projections were based on estimates included in the three references mentioned above. NOx, CO and VOC emissions estimates in lb/MWh are presented for each technology both with and without aftertreatment control (AT). For this analysis, aftertreatment was only included for the 800 kW and 3000 kW engines. The installed costs in Tables E7 through E10 are based on typical national averages.

In the cooling markets, an additional cost was added to reflect the costs of adding chiller capacity to the CHP system. These costs depend on the sizing of the absorption chiller which in turn depends on the amount of usable waste heat that the CHP system produces. Figure E-1 shows this cost approximation.

Figure E-1. Absorption Chiller Capital Costs



[20] "Assessment of Emerging Low-Emissions Technologies for Distributed Resource Generators", EPRI, January 2005.

Table E-7. Reciprocating Engine Cost and Performance Characteristics

CHP System	Characteristic/Year Available	2007-2010	2010-2015	2016-2020
100 kW	Installed Costs, $/kW	$2,210	$1,925	$1,568
	Heat Rate, Btu/kWh	12,000	10,830	10,500
	Electric Efficiency, %	28.4%	31.5%	32.5%
	Thermal Output, Btu/kWh	6100	5093	4874
	O&M Costs, $/kWh	0.022	0.013	0.012
	NOx Emissions, lbs/MWh (w/ AT)	0.10	0.15	0.15
	CO Emissions w/AT, lb/MWh	0.32	0.60	0.30
	VOC Emissions w/AT, lb/MWh	0.10	0.09	0.05
	PMT 10 Emissions, lb/MWh	0.11	0.11	0.11
	SO_2 Emissions, lb/MWh	0.0068	0.0064	0.0062
	After-treatment Cost, $/kW	incl.	incl.	incl.
800 kW	Installed Costs, $/kW	$1,640	$1,443	$1,246
	Heat Rate, Btu/kWh	9,760	9,750	9,225
	Electric Efficiency, %	35.0%	35.0%	37.0%
	Thermal Output, Btu/kWh	2313	3791	3250
	O&M Costs, $/kWh	0.013	0.01	0.009
	NOx Emissions, lbs/MWh (w/ AT)	0.5	1.24	0.93
	CO Emissions w/AT, lb/MWh	1.87	0.45	0.31
	VOC Emissions w/AT, lb/MWh	0.47	0.05	0.05
	PMT 10 Emissions, lb/MWh	0.10	0.01	0.01
	SO_2 Emissions, lb/MWh	0.0068	0.0057	0.0054
	After-treatment Cost, $/kW	300	190	140
3000 kW	Installed Costs, $/kW	$1,130	$1,100	$1,041
	Heat Rate, Btu/kWh	9,492	8,750	8,325
	Electric Efficiency, %	35.9%	39.0%	41.0%
	Thermal Output, Btu/kWh	3510	3189	2982
	O&M Costs, $/kWh	0.011	0.0083	0.008
	NOx Emissions, lbs/MWh (w/ AT)	1.52	1.24	0.775
	CO Emissions w/AT, lb/MWh	0.78	0.31	0.31
	VOC Emissions w/AT, lb/MWh	0.34	0.10	0.10
	PMT 10 Emissions, lb/MWh	0.01	0.01	0.01
	SO_2 Emissions, lb/MWh	0.0057	0.0051	0.0049
	After-treatment Cost, $/kW	200	130	100
5000 kW	Installed Costs, $/kW	$1,130	$1,099	$1,038
	Heat Rate, Btu/kWh	8,758	8,325	7,935
	Electric Efficiency, %	39.0%	41.0%	43.0%
	Thermal Output, Btu/kWh	3046	2797	2605
	O&M Costs, $/kWh	0.009	0.008	0.008
	NOx Emissions, lbs/MWh (w/ AT)	1.55	1.24	0.775
	CO Emissions w/AT, lb/MWh	0.75	0.31	0.31
	VOC Emissions w/AT, lb/MWh	0.22	0.10	0.10
	PMT 10 Emissions, lb/MWh	0.01	0.01	0.01
	SO_2 Emissions, lb/MWh	0.0054	0.0049	0.0047
	After-treatment Cost, $/kW	150	115	80

Table E-8. Microturbine Cost and Performance Characteristics

CHP System	Characteristic/Year Available	2007-2010	2010-2015	2016-2020
60 kW	Installed Costs, $/kW	$2,739	$2,037	$1,743
	Heat Rate, Btu/kWh	13,891	12,500	11,375
	Electric Efficiency, %	24.6%	27.3%	30.0%
	Thermal Output, Btu/kWh	6308	3791	3102
	O&M Costs, $/kWh	0.022	0.016	0.012
	NOx Emissions, lbs/MWh (w/ AT)	0.15	0.14	0.13
	CO Emissions w/AT, lb/MWh	0.24	0.22	0.20
	VOC Emissions w/AT, lb/MWh	0.03	0.03	0.02
	PMT 10 Emissions, lb/MWh	0.22	0.20	0.19
	SO_2 Emissions, lb/MWh	0.0079	0.0074	0.0067
	After-treatment Cost, $/kW			
250 KW	Installed Costs, $/kW	$2,684	$2,147	$1,610
	Heat Rate, Btu/kWh	13,080	11,750	10,825
	Electric Efficiency, %	2.6%	29.0%	31.5%
	Thermal Output, Btu/kWh	4800	3412	2625
	O&M Costs, $/kWh	0.015	0.013	0.012
	NOx Emissions, lbs/MWh (w/ AT)	0.43	0.24	0.13
	CO Emissions w/AT, lb/MWh	0.26	0.26	0.24
	VOC Emissions w/AT, lb/MWh	0.03	0.03	0.02
	PMT 10 Emissions, lb/MWh	0.18	0.18	0.16
	SO_2 Emissions, lb/MWh	0.0070	0.0069	0.0064
	After-treatment Cost, $/kW	500	200	90

Table E-9. Fuel Cell Cost and Performance Characteristics

CHP System	Characteristic/Year Available	2007-2010	2010-2015	2016-2020
200 kW PAFC in 2005 150 kW PEMFC in outyears	Installed Costs, $/kW	$6,310	$4,782	$3,587
	Heat Rate, Btu/kWh	9,480	9,480	8,980
	Electric Efficiency, %	36.0%	36.0%	38.0%
	Thermal Output, Btu/kWh	4250	3482	3281
	O&M Costs, $/kWh	0.038	0.017	0.015
	NOx Emissions, lbs/MWh (w/ AT)	0.06	0.05	0.04
	CO Emissions w/AT, lb/MWh	0.07	0.07	0.07
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.00	0.00	0.00
	SO_2 Emissions, lb/MWh	0.0057	0.0056	0.0053
	After-treatment Cost, $/kW	n.a.	n.a.	n.a.
300 kW MCFC	Installed Costs, $/kW	$5,580	$4,699	$3,671
	Heat Rate, Btu/kWh	8,022	7,125	6,920
	Electric Efficiency, %	42.5%	47.9%	49.3%
	Thermal Output, Btu/kWh	1600	1723	1602
	O&M Costs, $/kWh	0.035	0.02	0.015
	NOx Emissions, lbs/MWh (w/ AT)	0.1	0.05	0.04
	CO Emissions w/AT, lb/MWh	0.07	0.05	0.04
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.00	0.00	0.00
	SO_2 Emissions, lb/MWh	0.0057	0.0042	0.0041
	After-treatment Cost, $/kW	n.a.	n.a.	n.a.
1200 kW MCFC	Installed Costs, $/kW	$5,250	$4,523	$3,554
	Heat Rate, Btu/kWh	8,022	7,110	6,820
	Electric Efficiency, %	42.5%	48.0%	50.0%
	Thermal Output, Btu/kWh	1583	1706	1503
	O&M Costs, $/kWh	0.032	0.019	0.015
	NOx Emissions, lbs/MWh (w/ AT)	0.05	0.05	0.04
	CO Emissions w/AT, lb/MWh	0.04	0.04	0.03
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.00	0.00	0.00
	SO_2 Emissions, lb/MWh	0.0044	0.0042	0.0040
	After-treatment Cost, $/kW	n.a.	n.a.	n.a.

Table E-10. Gas Turbine Cost and Performance Characteristics

CHP System	Characteristic/Year Available	2007-2010	2010-2015	2016-2020
3000 KW GT	Installed Costs, $/kW	$1,690	$1,560	$1,300
	Heat Rate, Btu/kWh	13,100	12,650	11,200
	Electric Efficiency, %	26.0%	27.0%	30.5%
	Thermal Output, Btu/kWh	5018	4489	4062
	O&M Costs, $/kWh	0.0074	0.0065	0.006
	NOx Emissions, lbs/MWh (w/ AT)	0.68	0.38	0.2
	CO Emissions w/AT, lb/MWh	0.55	0.53	0.47
	VOC Emissions w/AT, lb/MWh	0.03	0.03	0.02
	PMT 10 Emissions, lb/MWh	0.21	0.20	0.18
	SO_2 Emissions, lb/MWh	0.0070	0.0069	0.0069
	After-treatment Cost, $/kW	210	175	150
10 MW GT	Installed Costs, $/kW	$1,298	$1,342	$1,200
	Heat Rate, Btu/kWh	11,765	10,800	9,950
	Electric Efficiency, %	29.0%	31.6%	34.3%
	Thermal Output, Btu/kWh	4674	4062	3630
	O&M Costs, $/kWh	0.007	0.006	0.005
	NOx Emissions, lbs/MWh (w/ AT)	0.67	0.37	0.2
	CO Emissions w/AT, lb/MWh	0.50	0.46	0.42
	VOC Emissions w/AT, lb/MWh	0.02	0.02	0.02
	PMT 10 Emissions, lb/MWh	0.20	0.18	0.17
	SO_2 Emissions, lb/MWh	0.0069	0.0064	0.0059
	After-treatment Cost, $/kW	140	125	100
40 MW GT	Installed Costs, $/kW	$972	$944	$916
	Heat Rate, Btu/kWh	9,220	8,865	8,595
	Electric Efficiency, %	37.0%	38.5%	39.7%
	Thermal Output, Btu/kWh	3189	3019	2892
	O&M Costs, $/kWh	0.004	0.004	0.004
	NOx Emissions, lbs/MWh (w/ AT)	0.55	0.2	0.1
	CO Emissions w/AT, lb/MWh	0.04	0.04	0.04
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.16	0.15	0.15
	SO_2 Emissions, lb/MWh	0.0054	0.0052	0.0051
	After-treatment Cost, $/kW	90	75	40

E.4.Market Penetration Analysis

EEA has developed a CHP market penetration model that estimates cumulative CHP market penetration in 5-yrar increments. For this analysis, the forecast periods are 2012, 2017, and 2022. These results are interpolated to the output years 2010, 2015, 2020, and 2025. The target market is comprised of the facilities that make up the technical market potential as defined in previously in this section. Thee economic competition module in the market penetration model compares CHP technologies to purchased fuel and power in 5 different sizes and 4 different CHP application types. The calculated payback determines the potential pool of customers that would consider accepting the CHP investment as economic. Additional, non economic screening factors are applied that limit the pool of customers that can accept CHP in any given market/size. Based on this calculated economic potential, a market diffusion model is used to determine the cumulative market penetration for each 5-year time period. The cumulative market penetration, economic potential and technical potential are defined as follows:

- *Technical potential* represents the total capacity potential from existing and new facilities that are likely to have the appropriate physical electric and thermal load characteristics that would support a CHP system with high levels of thermal utilization during business operating hours.
- *Economic potential*, as shown in the table, reflects the share of the technical potential capacity (and associated number of customers) that would consider the CHP investment economically acceptable according to a procedure that is described in more detail below.
- *Cumulative market penetration* represents an estimate of CHP capacity that will actually enter the market between 2008 and 2025. This value discounts the economic potential to reflect non-economic screening factors and the rate that CHP is likely to actually enter the market.

In addition to segmenting the market by size, as shown in the table, the analysis is conducted in four separate CHP market applications (high load and low load factor traditional CHP and high and low load factor CHP with cooling.) These markets are considered individually because both the annual load factor and the installation and operation of thermally activated cooling has an impact on the system economics.

Economic potential is determined by an evaluation of the competitiveness of CHP versus purchased fuel and electricity. The projected future fuel and electricity prices and the cost and performance of CHP technologies determine the economic competitiveness of CHP in each market. CHP technology and performance assumptions appropriate to each size category and region were selected to represent the competition in that size range (**Table E-11**). Additional assumptions were made for the competitive analysis. Technologies below 1 MW in electrical capacity are assumed to have an economic life of 10 years. Larger systems are assumed to have an economic life of 15 years. Capital related amortization costs were based on a 10% discount rate. Based on their operating characteristics (each category and each size bin within the category have specific assumptions about the annual hours of CHP operation (80-90% for the high load factor cases with appropriate adjustments for low load factor facilities), the share of recoverable thermal energy that gets utilized (80%-90%), and the share of useful thermal energy that is used for cooling compared to traditional heating. The economic figure-of-merit chosen to reflect this competition in the market penetration model is simple payback.[21] While not the most sophisticated measure of a project's performance, it is nevertheless widely understood by all classes of customers.

[21] Simple payback is the number of years that it takes for the annual operating savings to repay the initial capital investment.

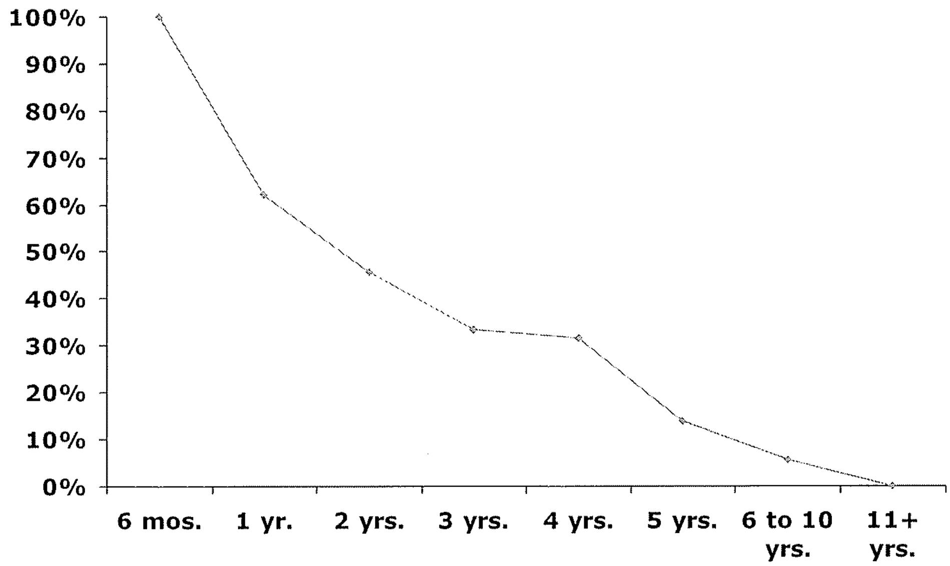
Table E-11. Technology Competition Assumed within Each Size Category

Market Size Bins	*Competing Technologies*
50 - 500 kW	100 kW Recip Engine
	70 kW Microturbine
	150 kW PEM Fuel Cell
500 - 1,000 kW	300 kW Recip Engine (multiple units)
	70 kW Microturbine (multiple units)
	250 kW MC/SO Fuel Cell (multiple units)
1 - 5 MW	3 MW Recip Engine
	3 MW Gas Turbine
	2 MW MC Fuel Cell
5 - 20 MW	5 MW Recip Engine
	5 MW Gas Turbine
20 - 100 MW	40 MW Gas Turbine

Rather than use a single payback value, such as 3-years or 5-years as the determinant of economic potential, we have based the market acceptance rate on a survey of commercial and industrial facility operators concerning the payback required for them to consider installing CHP. Figure E-2 shows the percentage of survey respondents that would accept CHP investments at different payback levels[22]. As can be seen from the figure, more than 30% of customers would reject a project that promised to return their initial investment in just one year. A little more than half would reject a project with a payback of 2 years. This type of payback translates into a project with an ROI of between 49-100%. Potential explanations for rejecting a project with such high returns is that the average customer does not believe that the results are real and is protecting himself from this perceived risk by requiring very high projected returns before a project would be accepted, or that the facility is very capital limited and is rationing its capital raising capability for higher priority projects (market expansion, product improvement, etc.).

[22] "Assessment of California CHP Market and Policy Options for Increased Penetration", California Energy Commission, July, 2005.

Figure E-2. Customer Payback Acceptance Curve



Source: *Primen's 2003 Distributed Energy Market Survey*

For each market segment, the economic potential represents the technical potential multiplied by the share of customers that would accept the payback calculated in the economic competition module.

The estimation of market penetration includes both a non-economic screening factor and a factor that estimates the rate of market penetration (diffusion.) The non-economic screening factor was applied to reflect the share of each market size category (i.e., applications of 50 to 500 kW, applications of 500 to 1,000 kW, etc) within the economic potential that would be willing and able to consider CHP at all. These factors range from 32% in the smallest size bin (50-500 kW) to 64% in the largest size bin (more than 20 MW.) These factors are intended to take the place of a much more detailed screening that would eliminate customers that do not actually have appropriate electric and thermal loads in spite of being within the target markets, do not use gas or have access to gas, do not have the space to install a system, do not have the capital or credit worthiness to consider investment, or are otherwise unaware, indifferent, or hostile to the idea of adding CHP. The specific value for each size bin was established based on an evaluation of EIA facility survey data and gas use statistics from the iMarket database.

The rate of market penetration is based on a *Bass diffusion curve* with allowance for growth in the maximum market. This function determines cumulative market penetration for each 5-year period. Smaller size systems are assumed to take a longer time to reach maximum market penetration than larger systems. Cumulative market penetration using a Bass diffusion curve takes a typical S-shaped curve. In the generalized form used in this analysis, growth in the number of ultimate adopters is allowed. The curves shape is determined by an initial market penetration estimate, growth rate of the technical market potential, and two factors described as *internal market influence* and *external market influence.*

The cumulative market penetration factors reflect the economic potential multiplied by the non-economic screening factor (maximum market potential) and by the Bass model market cumulative market penetration estimate.

Once the market penetration is determined, the competing technology shares within a size/utility bin are based on a *logit function* calculated on the comparison of the system paybacks. The greatest market share goes to the lowest cost technology, but more expensive technologies receive some market share depending on how close they are to the technology with the lowest payback. (This technology allocation feature is part of the EEA CHP model that is not specifically used for this analysis.)

Three cases were run to show the effects of providing an economic stimulus for CHP market penetration consisting of a capital cost reduction of $500/kW and $1,000/kW for all CHP systems 5 MW and below. The results of the base case, without incentives, are shown in Table E-12. Table E-13 shows the results of the $500/kW incentive case. Table E-14 shows the results of the $1,000/kW incentive case.

Table E-12. Market Penetration Results for Base Case

CHP Measurement	2010	2015	2020	2025
Cumulative Market Penetration (MW)				
Industrial	48	249	411	468
Commercial/Institutional	3	47	109	146
Total	51	296	520	614
Avoided Cooling	0	2	6	6
Scenario Grand Total	51	299	526	620
Annual Electric Energy (Million kWh)				
Industrial	389	1,975	3,237	3,641
Commercial/Institutional	20	314	707	963
Total	409	2289	3944	4604
Avoided Cooling	0	6	16	23
Scenario Grand Total	409	2,295	3,961	4,627
Incremental Onsite Fuel (billion Btu/year)				
Industrial	2,038	10,216	16,734	18,968
Commercial/Institutional	103	1,831	4,159	5,542
Total	2,141	12,047	20,893	24,510
Cumulative Net Investment (million 2006$)	$51	$317	$573	$689
Cumulative Incentive Payments (Million 2006$)	$0	$1	$4	$7

Note: Incentive Payments in the Base Case represent fuel cell tax credits

Table E-13. Market Penetration Results for $500/kW Incentive Case

CHP Measurement	Today	2010	2015	2020	2025
Cumulative Market Penetration (MW)					
Industrial	0	51	276	467	540
Commercial/Institutional	0	8	107	236	313
Total	0	59	382	703	853
Avoided Cooling	0	1	9	17	19
Scenario Grand Total	0	60	391	721	872
Annual Electric Energy (Million kWh)					
Industrial	0	402	2,127	3,549	4,028
Commercial/Institutional	0	48	650	1,437	1,925
Total	0	450	2776	4986	5954
Avoided Cooling	0	2	22	49	67
Scenario Grand Total	0	453	2,799	5,035	6,020
Incremental Onsite Fuel (billion Btu/year)					
Industrial	0	2,118	11,103	18,613	21,395
Commercial/Institutional	0	274	3,866	8,564	11,304
Total	0	2,392	14,969	27,177	32,699
Cumulative Net Investment (million 2006$)	0	$58	$352	$630	$753
Cumulative Incentive Payments (Million 2006$)	0	$8	$96	$218	$294

Table E-14. Market Penetration Results for $1000/kW Incentive Case

CHP Measurement	Today	2010	2015	2020	2025
Cumulative Market Penetration (MW)					
Industrial	0	57	309	522	601
Commercial/Institutional	0	25	227	470	603
Total	0	82	536	992	1204
Avoided Cooling	0	1	10	19	21
Scenario Grand Total	0	83	546	1,011	1,225
Annual Electric Energy (Million kWh)					
Industrial	0	437	2,369	3,987	4,532
Commercial/Institutional	0	171	1,472	2,995	3,848
Total	0	608	3841	6982	8379
Avoided Cooling	0	3	27	57	77
Scenario Grand Total	0	611	3,867	7,039	8,456
Incremental Onsite Fuel (billion Btu/year)					
Industrial	0	2,376	12,557	21,060	24,142
Commercial/Institutional	0	952	8,490	17,392	22,200
Total	0	3,328	21,046	38,452	46,342
Cumulative Net Investment (million 2006$)	0	$66	$350	$599	$703
Cumulative Incentive Payments (Million 2006$)	0	$32	$289	$597	$764

Appendix F - The Deeper Model and Macro Model

The Dynamic Energy Efficiency Policy Evaluation Routine—or the DEEPER Model—is a 15-sector quasi-dynamic input-output impact model of the U.S. economy.[23] Although an updated model with a new name, the model has a 16-year history of use and development. See, for example, Laitner, Bernow, and DeCicco (1998) and Laitner and McKinney (2008a) for a review of past modeling efforts. The model is generally used to evaluate the macroeconomic impacts of a variety of energy efficiency (including renewable energy) and climate policies at both the state and national level. The national model now evaluates policies for the period 2008 through 2050. For the Virginia specific analysis, however, DEEPER Model covers the period between 2008 through 2025. As it is now designed, the model accepts policy inputs in the form of investments and expenditures as described throughout the report. It then evaluates the changed pattern of expenditures for the net direct and indirect impacts on the different sectors of the regional economy. DEEPER is an Excel-based analytical tool that consists generally of six sets of key modules or groups of worksheets. These six sets of modules now include:

Global data: The information in this module consists of the economic time series data and key model coefficients and parameters necessary to generate the final model results. The time series data includes the projected reference case energy quantities such as trillion Btus and kilowatt-hours, as well as the key energy prices associated with their use. It also includes the projected gross domestic product, wages and salary earnings, and levels of employment as well as information on key technology cost and performance characteristics. The sources of economic information include data from the Energy Information Administration, the Bureau of Economic Analysis, the Bureau of Labor Statistics, and Economy.com. The cost and performance characterization of key technologies is derived from available studies completed by ACEEE and others, as well as data from the Energy Information Administration's (EIA) National Energy Modeling System (NEMS). One of the more critical assumptions in this study is that alternative patterns of electricity consumption will change and/or defer the mix of investments in conventional power plants. Although we can independently generate these impacts within DEEPER, we can also substitute assumptions from the ICF Integrated Planning Model (IPM) and similar models as they may have different characterizations of avoided costs or alternative patterns of power plant investment and spending.

Macroeconomic model: This set of modules contains the "production recipe" for the region's economy for a given "base year"—in this case, 2006, which is the latest year for which a complete set of economic accounts are available for the regional economy. The I-O data, currently purchased from the Minnesota IMPLAN Group (IMPLAN 2008), is essentially a set of input-output accounts that specify how different sectors of the economy buy (purchase inputs) from and sell (deliver outputs) to each other. In this case, the model is now designed to evaluate impacts for 15 different sectors, including: Agriculture, Oil and Gas Extraction, Coal Mining, Other Mining, Construction, Manufacturing, Electric Utilities, Natural Gas Distribution, Transportation and Other Public Utilities (including water and sewage), Wholesale & Retail Trade, Services, Finance, Government, and Households.

Investment, Expenditures and Energy Savings: Based on the scenarios mapped into the model, this worksheet translates the energy policies into a dynamic array of physical energy impacts, investment flows, and energy expenditures over the desired period of analysis. It estimates the needed investment path for an alternative mix of energy efficiency and other technologies (including efficiency gains on both the end-use and the supply side). It also provides an estimate of the avoided

[23] There is nothing particularly special about this number of sectors. The goal is to provide sufficient detail to show key negative and positive impacts while maintaining a manageable sized model. If we choose to reflect a different mix of sectors and stay within the 15 x 15 matrix, that can be done easily. If we wish to expand the number of sectors, that would take some minor programming changes or adjustments to reflect the larger matrix.

investments needed by the electric generation sector. These quantities and expenditures feed directly into the final demand module of the model which then provides the accounting that is needed to generate the set of annual changes in final demand (see the related module description below).

Price dynamics: There are two critical drivers that impact energy prices within DEEPER. The first is a set of carbon charges that are added to retail prices of energy depending on the level of desired level of emission reductions and also depending on the available set of alternatives to achieve those reductions. The second is the price of energy as it might be affected by changed consumption patterns. In this case DEEPER employs an independent algorithm to generate energy price impacts as they reflect changed demand. Hence, the reduced demand for natural gas in the end-use sectors, for example, might offset increased demand by utility generators. If the net change is a decrease in total natural gas consumption, the wellhead prices might be lowered. Depending on the magnitude of the carbon charge, the change in retail prices might either be higher or lower than the set of reference case prices. This, in turn, will impact the demand for energy as it is reflected in the appropriate modules. In effect, then, DEEPER scenarios rely on both a change in prices and quantities to reflect changes in overall investments and expenditures.

Final demand: Once the changes in spending and investments have been established and adjusted to reflect changes in prices within the other modules of DEEPER, the net spending changes in each year of the model are converted into sector-specific changes in final demand. This, in turn, drives the input-output model according to the following predictive model:

$$X = (I-A)^{-1} * Y$$

where:

X = total industry output by sector
I = an identity matrix consisting of a series of 0's and 1's in a row and column format for each sector (with the 1's organized along the diagonal of the matrix)
A = the production or accounting matrix also consisting of a set of production coefficients for each row and column within the matrix
Y = final demand, which is a column of net changes in final demand by sector

This set of relationships can also be interpreted as

$$\Delta X = (I-A)^{-1} * \Delta Y$$

which reads, a change in total sector output equals the inverted (I-A) matrix times a change in the final spending demand for each sector. Employment quantities are adjusted annually according to exogenous assumptions about labor productivity in each of the sectors (based on Bureau of Labor Statistics forecasts).

Results: For each year of the analytical time horizon (again out to 2025 for the Virginia specific analysis), the model copies each set of results into this module in a way that can also be exported to a separate report.

Further results from Virginia's DEEPER analysis is provided to show macroeconomic trends between 5-year time periods. Although similar 2015 & 2025 results were presented in the body of this report, differences between 5-year time periods offer more reference points for the reader to understand Virginia's macroeconomic trends under the efficiency scenario. This section highlights the net changes Virginia's economy will experience as the result of our efficiency scenario.

Changes in Virginia's electricity production patterns from the efficiency scenario in comparison to the reference case are summarized in Table F.1, for the selected years 2010, 2015, 2020 and 2025. Again, these patterns are driven by the energy efficiency policy initiatives outlined in the policy analysis. Note that in comparison to the reference case the efficiency scenario rises/falls etc.

Table F.1. Changes in Virginia Electricity Production and Financial Impacts from Energy Efficiency Policy Scenario: 2010, 2015, 2020 & 2025

(Millions of 2006 $)*	2010	2015	2020	2025
Annual Total Cost**	$187	$575	$676	$668
Savings Relative to Reference Case:				
Cumulative Savings (GWh)	1,144	9,957	19,892	27,914
Cumulative Savings (%)	1.0%	7.9%	14.6%	19.4%
(Millions of 2006 $)*				
Annual Consumer Outlays	$171	$698	$935	$947
Annual Electricity Savings***	$106	$866	$1,696	$2,448
Annual Price of Electricity Savings***	$34	$312	$613	$681
Annual Net Consumer Savings	-$31	$480	$1,374	$2,182
Cumulative Net Energy Savings	-$69	$1,091	$5,673	$15,189

* 'Annual' refers to the given benchmark year, 'Cumulative' is the sum total from previous years begging with 2008.
**Annual total costs include administrative costs to run programs, incentives provided to consumers, and investments in energy efficiency devices (investments are from both utilities and consumers).
***Annual Electricity Savings is the amount of electricity that consumers save and its associated value in lowered energy bills. Annual Price of Electricity Savings are additional savings due to reductions in the *price* of electricity. Since consumers are using less electricity, demand falls, so then price.

The macroeconomic module of the DEEPER model traces how each set of policies transforms the Virginia economy in each year of the assessment period. Given the policy and program expenditures for the benchmark years, 2010, 2015, 2020 and 2025, the estimated changes in sectoral spending are provided in Table F.2. The module combined with estimated changes in sectoral spending then estimates the number of jobs and amount of wages each sector provides the Virginia economy. Although net jobs and wages were discussed in the body of this paper, additional values for the years 2010 and 2020 are provided in Table F.3.

Table F.2. Changes in Sector Spending (Millions of 2006 Dollars)

Sector	2010	2015	2020	2025
Agriculture	$0.0	$2.1	$8.7	$14.6
Oil and Gas Extraction	$0.1	$2.4	$11.0	$18.7
Coal Mining	$0.0	$0.0	$0.2	$0.3
Other Mining	$0.0	$1.0	$4.3	$7.3
Construction	-$25.0	-$354.4	$348.8	$499.7
Manufacturing	-$2.0	$25.4	$89.4	$147.6
Petroleum Refining	$0.2	$15.3	$66.9	$113.0
Electric Utility Services	$330.7	$178.5	-$289.3	-$468.2
Natural Gas Utility Services	-$0.1	$0.7	$2.3	$3.7
Transportation Other Public Utilities	-$3.5	-$6.8	-$4.8	-$0.2
Wholesale Trade	-$3.9	$55.1	$149.6	$235.2
Services	-$5.1	$218.2	$559.1	$865.2
Financial Services	-$1.3	-$10.1	-$50.7	-$39.2
Governmental Services	$3.5	$9.6	$15.7	$20.3

Table F.3. Economic Impact of Energy Efficiency Investment in Virginia: 2010, 2015, 2020 & 2025

Macroeconomic Impacts	2010	2015	2020	2025
Jobs (Actual)	964	675	7,392	9,820
Wages (Million $2006)	66	63	401	583
GSP (Million $2006)	216	202	628	882

There are other support spreadsheets as well as routines in visual basic programming that support the automated generation of model results and reporting. For more detail on the model assumptions and economic relationships, please refer to the forthcoming model documentation (Laitner and McKinney 2008b). For a review of how an I-O framework might be integrated into other kinds of modeling activities, see Hanson and Laitner (2007). While not an equilibrium model we borrow from some key concepts of mapping technology representation into DEEPER using the general scheme outlined in Laitner and Hanson (2007).

Advancing Energy Efficiency in Arkansas: Opportunities for a Clean Energy Economy

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Disclaimer*: While several organizations, including Navigant Consulting, ICF International, and Synapse Energy Economics assisted in the completion of this analysis and report, the ultimate viewpoints and recommendations expressed herein are those of ACEEE.*

Contents

Executive Summary

Recent policy developments have reinforced Arkansas' growth as a regional leader in energy efficiency. Under a directive from the Arkansas Public Service Commission (PSC) in 2007, Arkansas' electric and gas utilities began in 2008 to offer and promote their initial efficiency programs, known as "Quick Start" programs, for all sectors of the state economy. The Quick Start programs were approved by the PSC through December 31, 2009 with continuations and some enhancements approved for 2010. These will be followed by a more aggressive, "comprehensive" phase for which the details have recently been finalized at the PSC. On December 10, 2010, the PSC issued 10 Orders designed to expand the energy efficiency efforts of Arkansas utilities into the comprehensive phase, which included the adoption of an energy efficiency resource standard (EERS), making Arkansas only the second state in the Southeast region to do so. The PSC also issued a number of complementary orders that will bolster the efficacy of the EERS, such as the introduction of performance incentives; a lost revenue adjustment mechanism; and evaluation, verification, and measurement requirements. The PSC's leadership, in conjunction with greater activity within the Arkansas Energy Office (AEO) and complemented by unprecedented financial support from the *American Recovery and Reinvestment Act*, has signaled the state's commitment to transition from business-as-usual to a more robust, clean energy economy that will stimulate economic development and job growth while lowering energy bills and ensuring a rich quality of life for all Arkansans.

To build upon this commitment, this report presents a suite of energy efficiency policies and programs that have the potential to generate savings that by 2025 would satisfy virtually all of the projected growth in electricity consumption and reduce natural gas consumption by 8% below 2009 levels. And by making these investments in energy efficiency technologies and practices, Arkansas can add over 10,000 net jobs in 2025 and a net $3.1 billion in cumulative savings by 2025 through lower energy bills.

Despite these recent policy developments, there is still much work to be done to ensure that Arkansas benefits from the seeds it has sown. Increased investment in energy efficiency, supplemented by federal funding, has significantly expanded the role of the AEO. As part of the Arkansas Economic Development Commission, the AEO is tasked with helping to shape energy policy in the state through the funding and administration of state energy efficiency and renewable energy programs, a task made considerably more difficult with an annual budget ten times greater than it has been historically and limited staff to manage those funds. Meanwhile, the PSC has truly begun to exercise its authority, requiring annual savings targets for utilities while also adopting policies to ensure that utility investment in energy efficiency offers returns on par with capacity investments in order to remove the "throughput" incentive. Stringent reporting requirements will go a long way towards keeping utilities on target as well. However, this "comprehensive" phase is in its nascent stage and must be carefully cultivated and administered to maximize consumer benefits.

At stake is the sustained growth of an economy that ranks among the most energy-intensive nationwide: Arkansas' energy consumption per dollar of gross state product was the 11th highest in the country in 2007 (EIA 2010c). Arkansas also ranked 41st in ACEEE's *2009 State Energy Efficiency Scorecard* (Eldridge et al. 2009), which measures the efforts of states to embrace energy efficiency based on a broad range of policies. And while Arkansas is a predominantly rural state with relatively limited resources, aggressive energy efficiency investments could yield tremendous benefits. For example, Arkansas is a state that is heavily industrialized and home to several of the world's largest industrial manufacturers and commercial retailers. These companies not only offer local employment opportunities, but they are also major producers (and consumers) of energy-efficient products. Investments in energy efficiency not only represent a business opportunity in a burgeoning sector, but they also represent a way to help Arkansas consumers save on their energy bills—savings that can then be spent to further stimulate the Arkansas economy.

With these important issues is mind, this report presents the suite of policies and programs as well as a discussion of pertinent issues intended to guide policymakers and advocates as the state develops its comprehensive energy efficiency programs and further defines the roles that the AEO, PSC, and utilities

will play in the future. We present the results to help educate policymakers and the general public about the importance of efficiency, as well as to inform policy development in Arkansas over the next several years by identifying policy and technical opportunities for achieving major efficiency benefits.

Energy Policy Recommendations

This analysis attempts to both capture existing energy efficiency efforts and model a suite of new or expanded policies based on successful models implemented in other states as well as in-depth consultation with stakeholders in Arkansas. We recommend eleven specific energy-saving policies, and six enabling policies that provide a solid foundation for the former, as well as nine transportation policies (see Table ES-1). The Energy Efficiency Resource Standard represents the core of these policies, providing a foundation upon which other policies may be built to achieve the greatest savings. An EERS is a set of energy-saving targets that utilities are required to meet, initially starting at modest levels but steadily increasing over time. Of the eleven policies we are recommending, there are six that we suggest be eligible to contribute towards the EERS. But it is important to note that the EERS is simply an amalgamation of the savings generated by the individual policies and utility programs, so its absence does not preclude the efficacy of the policy and program recommendations included in this report.

Table ES-1. Summary of Energy Policy Recommendations

	Electricity & Natural Gas	Enabling Policies	Transportation
1	Energy Efficiency Resource Standard (EERS)	Energy Efficiency Clearinghouse	Clean Car Standard
2	Behavioral Initiative	Evaluation, Measurement and Verification	Pay-As-You-Drive Insurance
3	Weatherization of Severely Inefficient Homes	Financing	Transit Expansion / Concentration of Urban Development
4	Manufactured Homes Initiative	Lost-Revenue Recovery/Incentives	Reduced Light-Duty and Heavy-Duty Speeds
5	Industrial Initiative	Public Outreach	Efficient State Vehicle Fleet
6	Research, Development, and Demonstration Initiative	Workforce Development Initiative	Heavy Truck Efficiency Package
7	Rural & Agricultural Initiative		Truck Stop Electrification
8	Building Energy Codes, Voluntary Programs, and Enforcement		Freight Intermodal Investments
9	Combined Heat & Power (CHP)		Vehicle Electrification (discussion only)
10	Lead by Example (Energy Efficiency in State and Local Government Agencies)		
11	Demand Response Programs		

Electricity and Natural Gas

Our analysis includes a medium case and a high case scenario, both of which quantify the potential costs and benefits of the policies listed above, but differ in penetration rates of programs and levels of customer incentives. Table ES-2 shows the contribution of the individual policies and programs we recommend in the medium case in addition to the contribution from Arkansas' electric cooperatives given a requirement for them to meet savings similar to those required of investor-owned utilities under an energy efficiency resource standard. We estimate that these policies have the potential to meet 15% of projected electricity consumption and almost 14% of projected natural gas consumption by 2025 in the medium case scenario while reducing peak demand by 20% over the same period. These electric savings equate to almost all the projected consumption growth in electricity consumption through 2025 and can actually reduce natural gas consumption by 8% below 2009 sales levels. Additional savings from Arkansas' cooperative could drive electricity consumption 4% below 2009 sales levels.

Table ES-2. Summary of Energy Savings in 2025 by Policy and Program in the Medium Case

Policies and Programs	Electricity		Peak Demand		Natural Gas	
	GWh	%	MW	%	BBtu	%
Energy Efficiency Resource Standard (EERS)						
Residential Programs	*972*	*1.8%*	*205*	*1.8%*	*3,487*	*2.1%*
Commercial Programs	*1,451*	*2.6%*	*305*	*2.6%*	*5,089*	*3.1%*
Utility Programs Subtotal	***2,423***	***4.4%***	***510***	***4.4%***	***8,575***	***5.2%***
Behavioral Initiative	*163*	*0.3%*	*34*	*0.3%*	*435*	*0.3%*
Weatherization of Severely Inefficient Homes	*98*	*0.2%*	*21*	*0.2%*	*764*	*0.5%*
Manufactured Homes Initiative	*20*	*0.04%*	*4*	*0.04%*	*4*	*0.003%*
Manufacturing Initiative	*1,789*	*3.2%*	*377*	*3.2%*	*3,942*	*2.4%*
RD&D Initiative	*723*	*1.3%*	*152*	*1.3%*	*3,686*	*2.2%*
Rural and Agricultural Initiative	*159*	*0.3%*	*34*	*0.3%*	-	*0.0%*
EERS Subtotal	***5,375***	***9.8%***	***1,132***	***9.8%***	***17,406***	***10.6%***
Building Energy Codes	1,068	1.9%	225	*1.9%*	3,266	*2.0%*
Combined Heat and Power (CHP)	103	0.2%	13	*0.1%*	-	*0.0%*
Lead by Example	467	0.8%	98	*0.8%*	1,706	*1.0%*
Demand Response	NA	NA	877	*7.6%*	NA	NA
TOTAL	**7,013**	**13%**	**2,345**	**20%**	**22,260**	**14%**
Savings from Cooperatives	**955**	**2%**	**NA**	**NA**	**NA**	**NA**
GRAND TOTAL	**7,968**	**15%**	**2,345**	**20%**	**22,260**	**14%**

Figure ES-1. Share of Electricity Consumption Met by Energy Efficiency Policies

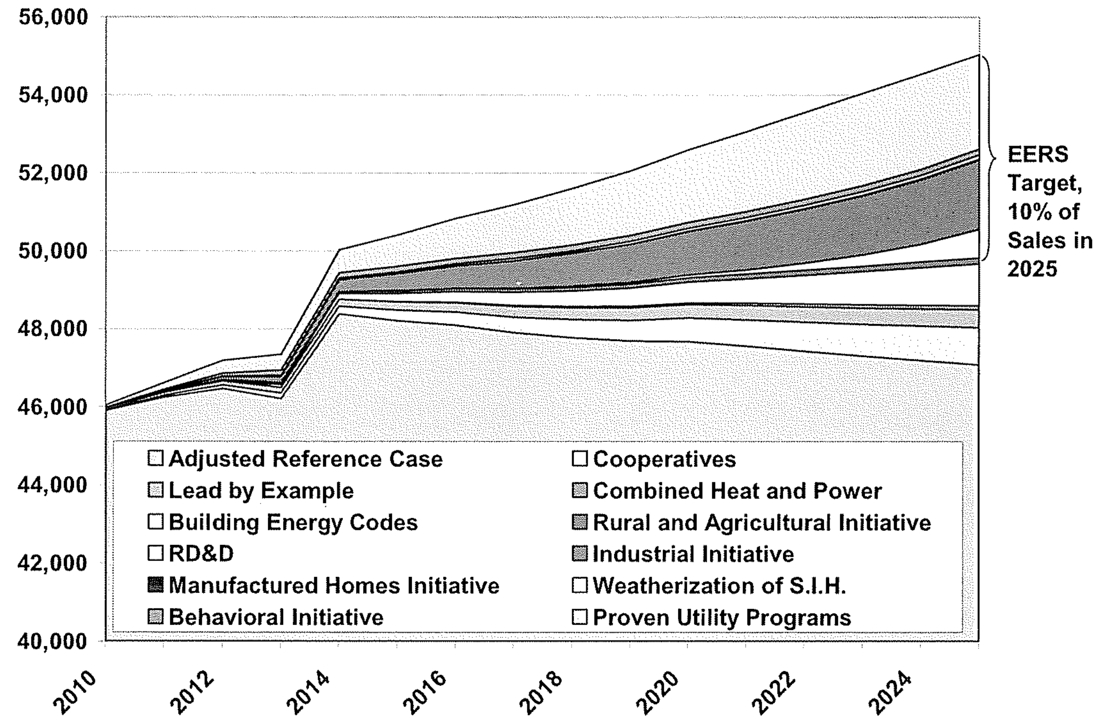
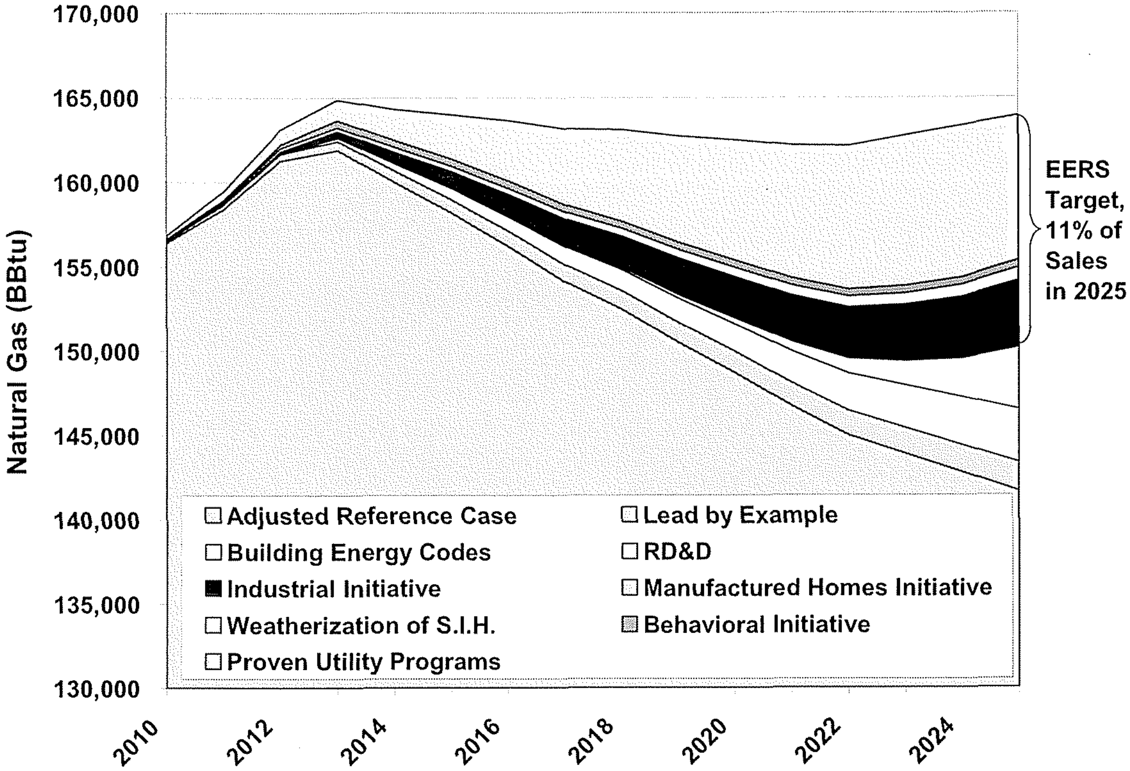


Figure ES-2. Share of Natural Gas Consumption Met by Energy Efficiency Policies



Transportation

Arkansas' gasoline and diesel fuel consumption has grown quickly in recent decades. In 2008, Arkansas' transportation sector consumed 292 trillion Btus of energy, 26% of total energy use in the state and about 1% of total transportation energy consumption in the United States.

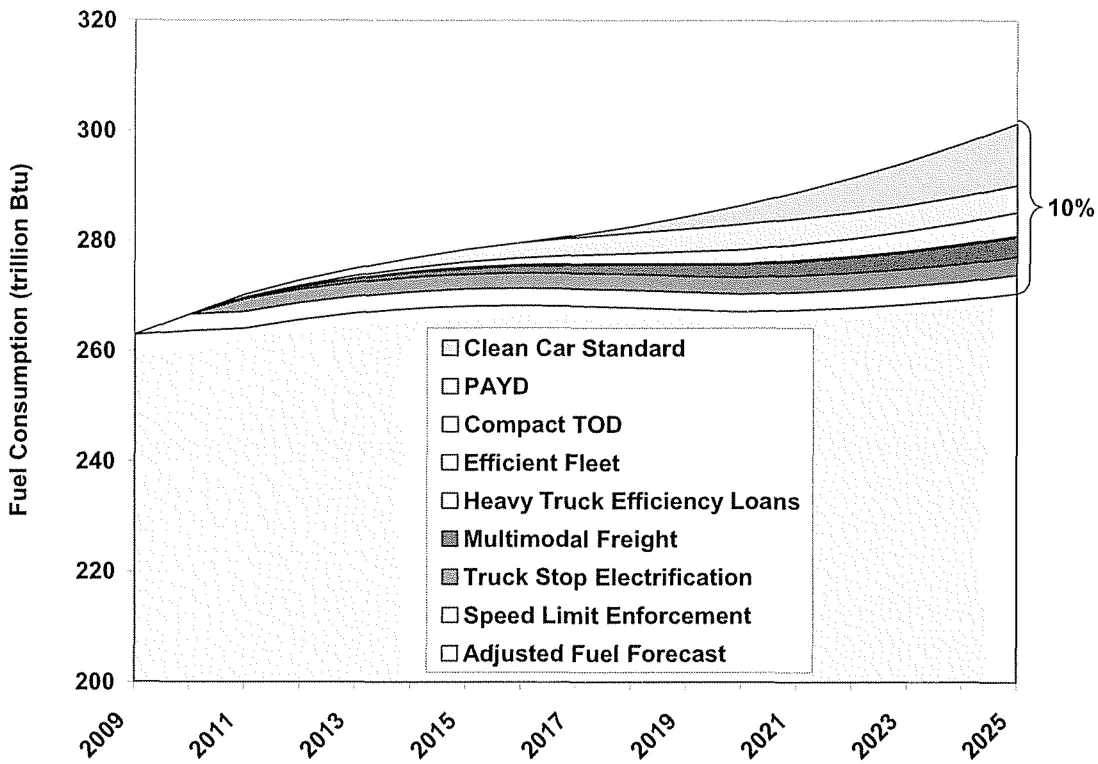
Arkansas' ability to slow such unsustainable fuel use lies in addressing not only vehicle fuel efficiency but also the overall efficiency of the state's transportation system. The nine transportation efficiency policies outlined in this report take advantage of the savings potential for both diesel and gasoline fuels (see Table ES-3). However, the disparate demographic make-up of Arkansas necessitates tailored transportation policy packages based on population and accessibility factors. Policies applicable to metropolitan areas may not be suitable for the parts of the state made up of rural communities. As a result, a number of our policies are focused on the two primary metropolitan regions in the state.

We estimate the total combined (diesel and gasoline) fuel savings to be approximately 10% by 2025 under the medium case scenario (see Figure ES-3). In the high case, transportation efficiency policies and programs have the potential to reduce fuel consumption by 12% by 2025.

Table ES-3. Summary of Transportation Savings by Policy or Program in the Medium Case

	Annual Transportation Savings by Policy (thousand barrels)	2015	2025	Savings in 2025 (%)
1	Clean Car Standard	0	2,130	5.6%
2	Pay-As-You-Drive Insurance	432	920	2.4%
3	Transit Expansion / Concentration of Urban Development	77	705	1.9%
4	Light-Duty Speed Limit Enforcement	399	419	1.1%
5	Efficient State Vehicle Fleet	7	9	<1%
	Total Gasoline Savings	**915**	**4,183**	**11.3%**
6	Heavy Truck Efficiency Package	29	35	0.2%
7	Truck Stop Electrification	554	680	3.8%
8	Freight Intermodal Investments	180	619	3.5%
9	Heavy-Duty Speed Limit Enforcement	171	196	1.1%
	Total Diesel Savings	**754**	**1,307**	**7.4%**

Figure ES-3. Total Gasoline and Diesel Savings from Transportation Efficiency Policies in the Medium Case Scenario



Impacts on Employment and the Economy from Energy Efficiency

The energy savings from these efficiency policies and programs can cut the net annual energy bills for customers by $1.9 million in 2025. While these savings will require some public and customer investment, by 2025 net cumulative savings on energy bills will reach $3.2 billion. These savings are the result of two effects. First, participants in energy efficiency programs will install efficiency measures, such as more efficient appliances or heating equipment, therefore lowering their electricity and natural gas consumption and electric and natural gas bills. In addition, because of the current volatility in energy prices, efficiency strategies have the added benefit of improving the balance of demand and supply in energy markets, thereby stabilizing regional electricity prices for the future.

Investments in efficiency policies and programs can also help create new, high-quality "green-collar" jobs in Arkansas while increasing both wages and gross state product (GSP). Our analysis shows that energy efficiency investments can create over 11,000 new, local jobs in Arkansas in 2025 (see Table ES-4), including well-paying trade and professional jobs needed to design, install, and operate energy efficiency measures. These new jobs, including both direct and indirect employment effects, would be equivalent to 90 typical new manufacturing facilities locating to the state.

Table ES-4. Economic Impacts from the Energy Efficiency Medium Case Policy Scenario

Macroeconomic Impacts	2015	2020	2025
Net Jobs (Actual)	7,820	6,828	11,399
Cumulative Net Energy-Bill Savings	$198	$623	$3,224
Wages (Million $2007)	$254	$175	$306
GSP (Million $2007)	$360	$119	$238

Conclusions

Arkansas has signaled its intent to move forward with more aggressive energy efficiency and the PSC has acted accordingly, issuing the 10 Orders along with its Sustainable Energy Resources Action Guide. But Arkansas' future success will be dependent upon the collective will of its political leadership, businesses, and citizens to move forward. Arkansas is at a turning point where the state and its policymakers can choose either to continue to depend upon conventional, aging energy resource generation, or choose to slow—or even to reduce—future demand for electricity and natural gas by investing in energy efficiency. As this assessment demonstrates, there are plenty of cost-effective energy efficiency opportunities in the state. However, these opportunities will not be realized without careful consideration of how best to position Arkansas' government agencies, regulators, businesses, and citizens as the state continues to pursue energy efficiency.

Arkansas cannot afford to ignore the potential economic benefits energy efficiency can create for its homes, businesses, and industries. While all of the options for the state's energy future bear costs, this analysis suggests that making greater and sustained investments in cost-effective energy efficiency as a demand-side resource will create positive returns for citizens and businesses in the state. Furthermore, such efficiency savings reduce the need for expensive, new power plants, helping to constrain rate increases. Efficiency is a win-win strategy to meet the state's growing energy needs while creating a net benefit to the economy in lower energy bills and net job creation.

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About the American Council for an Energy-Efficient Economy

ACEEE is a nonprofit organization dedicated to advancing energy efficiency as a means of promoting economic prosperity, energy security, and environmental protection. For more information, see aceee.org. ACEEE fulfills its mission by:

- Conducting in-depth technical and policy assessments
- Advising policymakers and program managers
- Working collaboratively with businesses, public interest groups, and other organizations
- Organizing conferences and workshops
- Publishing books, conference proceedings, and reports
- Educating consumers and businesses

Projects are carried out by staff and selected energy efficiency experts from universities, national laboratories, and the private sector. Collaboration is key to ACEEE's success. We collaborate on projects and initiatives with dozens of organizations including federal and state agencies, utilities, research institutions, businesses, and public interest groups.

Support for our work comes from a broad range of foundations, governmental organizations, research institutes, utilities, and corporations.

Chapter One: Introduction

The future of energy efficiency policy in Arkansas is no longer an uncertainty. Under a directive from the Arkansas Public Service Commission (PSC) in 2007, Arkansas' electric and gas utilities first began to offer and promote their initial efficiency programs for all sectors of the state economy in 2008. These "Quick Start" programs were developed to be limited in scope initially, though they created a solid foundation to build upon, pointing toward a future in which energy efficiency could become the rule rather than the exception. That future was realized on December 10, 2010, when the Arkansas Public Service Commission (PSC) issued 10 Orders designed to expand the energy efficiency efforts of Arkansas utilities. The Orders were issued after nearly two years of Commission inquiries in four separate dockets that involved public comments and hearings, sworn testimony, legal briefs, technical conferences, and public presentations by national leaders. These recent developments demonstrate that the state is poised to take considerable strides in implementing aggressive energy efficiency programs, thereby moving toward the ultimate goals of achieving sustainable economic development and a rich quality of life for its citizens.

In recent years, the predominant impetus for investments in energy efficiency in most states has been to curb growth in consumption and peak load because future demand was considered too great for current generation resources and related infrastructure to reliably support. However, growth in energy consumption across Arkansas over the past decade has been moderate and roughly similar to the rest of the United States. Since 2000, electricity consumption has grown at an average annual rate of 1.5% per year and is forecasted to grow more slowly in the future, at an average rate of 1% through 2025, with peak demand estimated to grow around 1.1% per year over the same period. Natural gas consumption, on the other hand, has actually *declined* at a rate of 1.3% per year since 2003, though consumption is expected to remain steady over the next decade.

Arkansas' primary concerns are focused more on stimulating economic growth and creating and retaining local jobs as opposed to constraining energy demand. Arkansas is not necessarily unique in this respect: the national unemployment rate in early 2010 is hovering near 10%, with unemployment in Arkansas falling slightly below that at 7.7%, leaving the state 18th relative to other states (BLS 2010). Gross state product, a measure of annual economic growth, has also steadily declined between 2005 and 2008, from 3.1% per year to 0.7%, on par with the national average (BEA 2010).

Arkansas is unique in that it is a heavily industrialized state—it has the fourth highest number of industrial electric customers in the nation—and that it is home to several of the world's largest industrial manufacturers and commercial retailers. These companies, such as Wal-Mart, Rheem, Baldor, Whirlpool, and Trane, not only offer tremendous local employment opportunities, but they are also major producers (and consumers) of energy-efficient products. And because demand for these types of manufactured goods fluctuates considerably in response to the strength of the national and global economy, it is crucial to the future vitality of Arkansas' economy that the state perpetuates the viability of these enterprises; especially as the United States and the rest of the world increase their purchases of energy-efficient appliances and equipment.

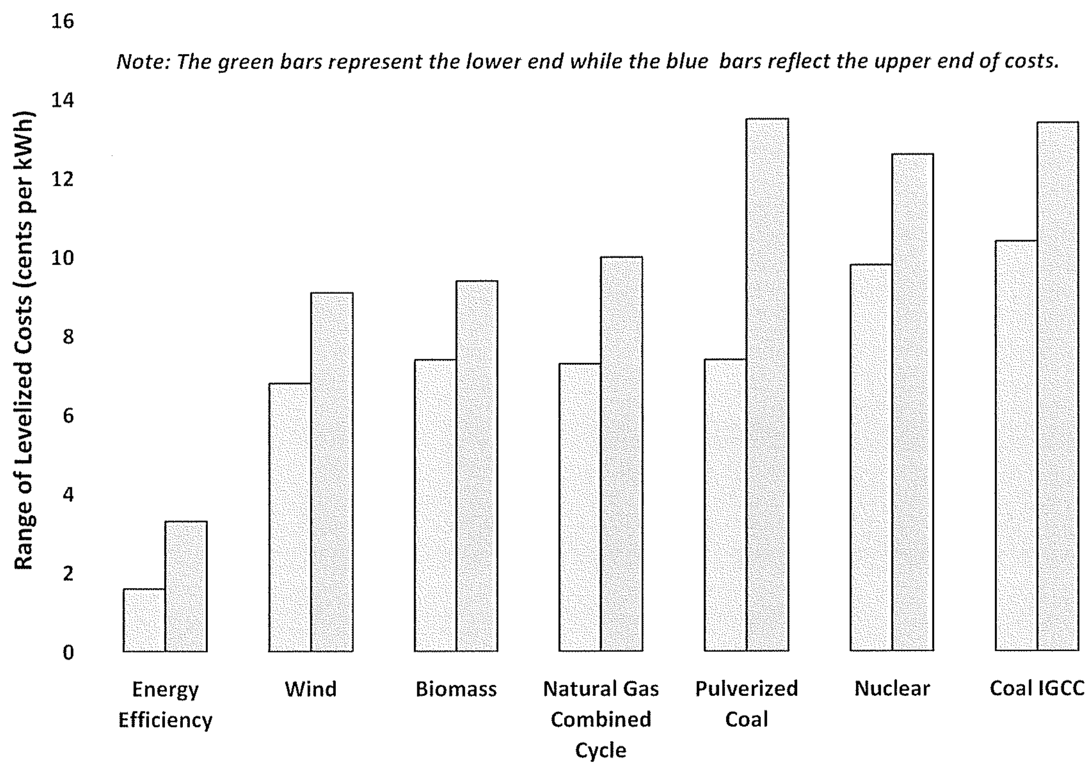
Consequently, efforts to stimulate the state economy and to create jobs will put an increasing strain on Arkansas' infrastructure beyond that tied to energy generation and transmission. Growing population and greater production of goods and services will require a contemporaneous investment in the Arkansas' transportation infrastructure to move these people and products. The state is expected to add over 3 million people by 2025, concentrated primarily in only a few metropolitan areas that are already vexed by snarling traffic, inadequate public transportation systems, and a lack of alternative transportation modes. Highly concentrated population growth and the attendant growth in vehicle traffic in these few metropolitan areas and freight corridors lead to major concerns about economic and environmental sustainability.

Harnessing Arkansas' Efficiency Potential

Arkansas has an opportunity to truly embrace energy efficiency as the state's "first fuel." Energy efficiency is not only the least-cost resource available to meet the energy and economic needs of the state in the long-term (see Figure 1-1), it is also the quickest to deploy for short-term impacts and has a net positive benefit on job creation. And unlike supply-side energy resources, efficiency and demand response are the only resources that can begin to reduce energy bills by decreasing overall consumption, thus freeing up dollars in consumer budgets and industry operating costs that can be spent to help expand the state's economy and spur development.

Energy efficiency and demand response can also delay the need for expensive new supply in the form of generation and transmission infrastructure investments (Elliott et al. 2007a, 2007b). Delaying considerable capital expenditures helps keep the future cost of electricity more affordable for the state and helps maintain the reliability of the power system. In addition, well-developed programs ensure that a greater share of the dollars invested in energy efficiency go to local companies that create new jobs compared with conventional electricity resources, where much of the money flows out of state to external equipment manufacturers and energy suppliers.

Figure 1-1. Levelized Utility Electricity Resource Cost in 2008



Source: Lazard (2008), except for (a): Energy efficiency program costs are the estimates of levelized costs of saved energy (CSE) for program administrator costs (PAC) as described in Friedrich et al. (2009).

Funding appropriated through the *American Recovery and Reinvestment Act* (ARRA) is providing Arkansas the financial means to begin to meet the state's economic and employment goals. ARRA allocated $40 million to the Arkansas Energy Office (AEO) for its State Energy Program (SEP), which will be dispersed to thirteen projects created by the AEO to target efficiency improvements across all sectors of the economy. ARRA also allocated $20.1 million in competitive grants for state and local projects through the Energy-Efficiency and Conservation Block Grant Program (EECBGP) and $48 million for its Weatherization Assistance Program. Prudently investing these funds in order to expand energy efficiency in the state will stimulate demand for locally-produced goods, which in turn will require a trained workforce capable of identifying, implementing, and operating energy-efficient goods and services. From auditors to operators, promoting energy efficiency will help to create tens of thousands of new, local, high quality "green-collar" jobs, helping to stimulate Arkansas' economy for the benefit of all its citizens.

The Roles of the Arkansas Energy Office and Public Service Commission

The state's Energy Conservation Endorsement Act of 1977 gave the Arkansas PSC the authority to "propose, develop, solicit, approve, require, implement, and monitor" energy efficiency programs "by companies" if the Commission finds that such programs and measures "will be beneficial to the ratepayers of such public utilities and to the utilities themselves." With that authority, in 2007 the PSC ordered electric and natural gas utilities to begin to fund and administer "Quick Start" energy efficiency programs, an introductory phase that ended December 31, 2009. A "comprehensive" phase for Arkansas' efficiency programs was set to begin January 1, 2010, though the definition of comprehensive had yet to be defined. In the meantime, the PSC, in an omnibus order released February 3, 2010, generally approved all utility programs, portfolios, and budgets for eighteen months while eleven issues related to the creation of comprehensive energy efficiency programs were explored in a variety of dockets, discussed among parties, and decided by the Commission over the course of 2010. The issues were considered in Docket Nos. 10-010-U (Energy Efficiency Notice of Inquiry), 08-137-U (Innovative Ratemaking), and 08-144-U (Sustainable Energy Resources).

On December 10, 2010, the PSC inquiries were finalized and Arkansas became the first state in the Southeast to adopt a comprehensive set of policies on utility energy efficiency programs, including an energy efficiency resource standard. The Arkansas PSC issued 10 Orders designed to expand the energy efficiency efforts of Arkansas utilities, including the adoption of an energy efficiency resource standard; the availability of performance incentives and lost revenue adjustment mechanisms for utilities; and evaluation, measurement, and verification requirements.

Meanwhile, the AEO, a division of the Arkansas Economic Development Commission (AEDC), is tasked with helping to shape and guide energy policy in the state through the funding and administration of statewide energy efficiency and renewable energy programs. The recent influx of federal stimulus funding has given the AEO a tremendous opportunity to establish a solid foundation for the development of robust energy efficiency programs. These programs extend from offering loans and rebates for efficiency improvements to training contractors and educating the general public. The AEO is also responsible for managing state and federal funds, such as the funds allocated for the SEP and EECBG programs.

ACEEE's Contribution

One of the primary goals of this study is to provide insight into many of the issues raised in the new energy efficiency dockets in order to help guide Arkansas policymakers as the state moves into the comprehensive energy efficiency program phase. Ensuring that the comprehensive phase is developed and augmented properly is crucial to the effectiveness of the long-term energy policy goals in the state. ACEEE recognizes that the direction and efficacy of energy efficiency programs and policies in Arkansas is ultimately the responsibility of the PSC and the AEO, though the involvement of the State Legislature will also be important.

In addition to providing insight on the issues surrounding the development of Arkansas' comprehensive energy efficiency programs as identified in the various energy efficiency dockets, we also suggest policies Arkansas could implement to facilitate the development of these energy efficiency resources across its residential, commercial, industrial, and transportation sectors. We present the results in a fashion designed to help educate policymakers and the general public about the importance of energy efficiency, as well as to inform policy development in Arkansas over the next several years by identifying policy and technical opportunities for achieving major energy benefits and savings. This is done with an eye toward honoring the state's own unique characteristics and needs as much as possible. It is not intended as a dictate to policymakers but rather as a guide to inform the state's future decision-making. Many states are already moving forward in this arena and initiatives taken by Arkansas can help it join the leaders among the states with a pay-off of lower energy costs for consumers, increased jobs, and added competitiveness and economic development.

To help facilitate Arkansas' progress, ACEEE is funded to provide technical assistance for eighteen months following the release of this report. Since we intend this report to be used as a roadmap to guide future efficiency resource decisions, it is important that ACEEE remains available to stakeholders to help in whatever capacity is necessary.

Analysis Methodology and Report Outline

Over the past several years, ACEEE has worked increasingly at the state level as a growing number of state legislatures, governors, and other public entities are showing interest and leadership in energy efficiency. ACEEE established a base for its future state work with the publication of the *State Energy Efficiency Scorecard for 2006*, which ranked all 50 states based on several energy efficiency strategies. A third edition of the report, *The 2009 State Energy Efficiency Scorecard*, was published in October 2009, and included analyses of the following categories:

1. Utility and Public Benefits Efficiency Programs and Policies
    a. Spending on Efficiency Programs (electricity)
    b. Annual Savings from Efficiency Programs (electricity)
    c. Spending on Efficiency Programs (natural gas)
    d. Targets (Energy Efficiency Resource Standards)
    e. Utility Incentives/Removal of Disincentives
2. Transportation
3. Building Energy Codes
4. Combined Heat and Power
5. State Government Initiatives
6. Appliance Efficiency Standards

Using the *Scorecard* findings, ACEEE identified several states in the process of implementing new energy efficiency strategies or expanding existing ones. These states became the focal point of ACEEE's State Clean Energy Resource Project.[1] The intent is to create a series of state assessments of efficiency resources and other clean energy strategies, and for ACEEE to serve as a center of information and expertise in order to support relevant policies at the state level. This assessment for Arkansas is the latest in this series of reports.

ACEEE uses a tripartite model in preparing its state assessments. The first step is to identify and meet, in person or via conference call, with appropriate stakeholders to discuss ideas, concerns, and priorities. In Arkansas, these stakeholders included, but are not limited to, the Public Service Commission, the Arkansas Energy Office, various state and local government officials, electric and natural gas utilities, industrial manufacturers, and environmental groups. Following the meetings with stakeholders, ACEEE and its project team performed its analysis of the state's overall energy efficiency resource potential, making specific policy, regulatory, and program suggestions that are the crux of the final report. The last step is the outreach to our stakeholders to share the results of the study, generally through a combination of press releases, conference presentations, and other communication tools. Copies of the report are free and made available at outreach events as well as on the ACEEE Web site.

[1] See http://www.aceee.org/sector/state-policy/scerp.

Analysis Methodology

The remainder of the report is organized into the following chapters. Here we provide a brief methodology of each section. Details to resource for most of these chapters can be found in the technical appendices that accompany the body of this report:

Chapter Two: Electricity & Natural Gas Markets

- ***Reference Case Forecasts:*** The first step in conducting an energy efficiency potential study for Arkansas was to collect data and to characterize the state's current and expected patterns of electricity and natural gas consumption over the time period of the study (2009–2025). In this section of the report we described the assumed reference forecasts for the two fuel sources. Reference case avoided costs for electric utilities, developed by Synapse Energy Economics, Inc., are shown in this section along with projections of retail energy prices. See Appendix A for detailed information.

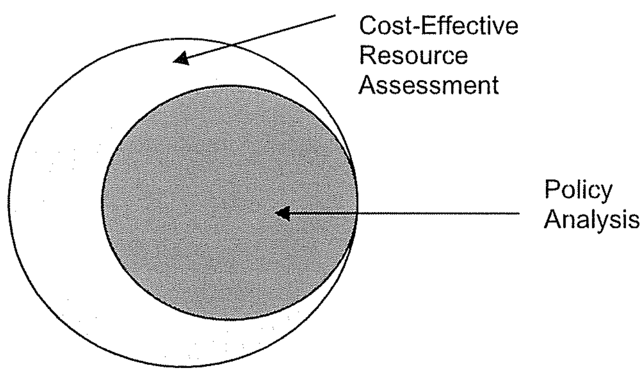
Chapter Three: Energy Efficiency Cost-Effective Resource Assessment

- The energy efficiency resource assessment examines the overall potential in the state for increased cost-effective efficiency using technologies and practices that are currently commercially available (see Appendix B for detailed information). Cost-effectiveness is evaluated from the customer's perspective (i.e., a measure is deemed cost-effective if its cost of saved energy is less than the average retail rate of energy). We review specific, efficient technology measures that are technically feasible for each sector; analyze costs, savings, and current market share/penetration; and estimate the total potential from implementation of the resource mix. The technology assessment is reported by sector (i.e., residential, commercial, and industrial) and includes an analysis of the potential for expanded CHP, which is prepared by ICF International.

Chapter Four: Energy Efficiency Policy Analysis

- ***Energy Efficiency Policy Analysis:*** For this analysis, we developed a suite of eleven energy efficiency policy recommendations based on successful models implemented in other states and in consultation with our stakeholders in Arkansas. This analysis assumes a reasonable program and policy implementation rate, and therefore is less than the overall resource potential (see Figure 1-2). We draw upon our resource assessment and evaluations of these policies in other states to estimate the energy savings and the investments required to realize the saving. The policy list for stakeholder review is presented after the reference forecast section in this document.

Figure 1-2. Levels of Energy Efficiency Potential Analysis



- ***Demand Response (DR) Analysis:*** The demand response analysis, which was prepared by Summit Blue Consulting, assesses current demand response activities in Arkansas, uses benchmark information to assess the potential for expanded activities in the state, and offers policy recommendations that could foster DR contributing appropriately to the resource mix in Arkansas that could be used to meet electricity needs. Potential load reductions are estimated for a set of DR programs that represent the technologies and customer types that span a range of DR efforts, and are in addition to the demand reductions resulting from expanded energy efficiency investments.

Chapter Five: Transportation Efficiency

- Evaluates nine policy options that Arkansas could adopt to improve light- and heavy-duty vehicle efficiency, reduce passenger and freight vehicle miles traveled, and coordinate land-use transportation planning in the state. The savings and costs for each policy are also presented along with adjusted gasoline and diesel consumption projections that reflect implementation of the policies.

Chapter Six: Combined Macroeconomic and Emissions Impacts from Electricity, Natural Gas, and Transportation Policies

- ***Macroeconomic Impacts:*** Based on the energy savings, program costs, and investment results from the policy analysis, we then run ACEEE's macroeconomic model, DEEPER, to estimate the policy impacts on jobs, wages, and GSP in Arkansas.

- ***Emissions Impacts:*** This section includes an estimation of potential carbon dioxide emissions reductions in Arkansas from improved energy efficiency in the electricity and natural gas markets.

Chapter Seven: Discussions and Conclusions

Chapter Two: Electricity and Natural Gas Markets

Background

The state of Arkansas consumes over 1.1 quads of total energy per year and in 2008 ranked 31st in the U.S. in total energy consumption and 32nd in population (see Table 2-1). Yet despite its low rankings in energy consumption and population, Arkansas is one of the most energy-intensive states in the nation, both in terms of per capita and per dollar of gross state product (GSP), ranking 17th and 11th in those categories, respectively (EIA 2010b, 2009c; Economy.com 2010). The significant energy consumption by Arkansas' industrial sector relative to other states definitely plays a role in the state's high ranking for per capita energy consumption.[2]

Table 2-1. Energy Intensity and Other Energy-Related Rankings in Arkansas, Relative to the Rest of the U.S.

Category	Rank
Electricity Consumption per Capita*	11th
Energy Consumption per Capita	17th
Energy Consumption per Dollar of GSP	11th
Total Electricity Consumption	30th
Total Energy Consumption	31st
Total Population	32nd

* ACEEE estimate (EIA 2010b; Economy.com 2010)

This report focuses on end-use energy efficiency opportunities for the state's residential, commercial, industrial, and transportation sectors, which account for 21%, 15%, 38%, and 26% of the total energy consumption in the state, respectively. In this section we discuss the current condition of the Arkansas electricity and natural gas markets, and the overall role of energy efficiency and related opportunities to meet the state's growing energy needs. The discussion of Arkansas' transportation sector follows in Chapter 5.

Electricity

Arkansas' electricity market is served by four investor-owned utilities (IOUs), seventeen electric cooperatives, and several municipal utilities (see Figure 2-1). Entergy Arkansas, Inc.[3] is a member of the Southeastern Electric Reliability Council while Southwestern Electric Power Company (SWEPCO), Oklahoma Gas & Electric (OG&E), and Empire District are members of the Southwest Power Pool. Arkansas cooperatives are collectively the second largest utility in the state.

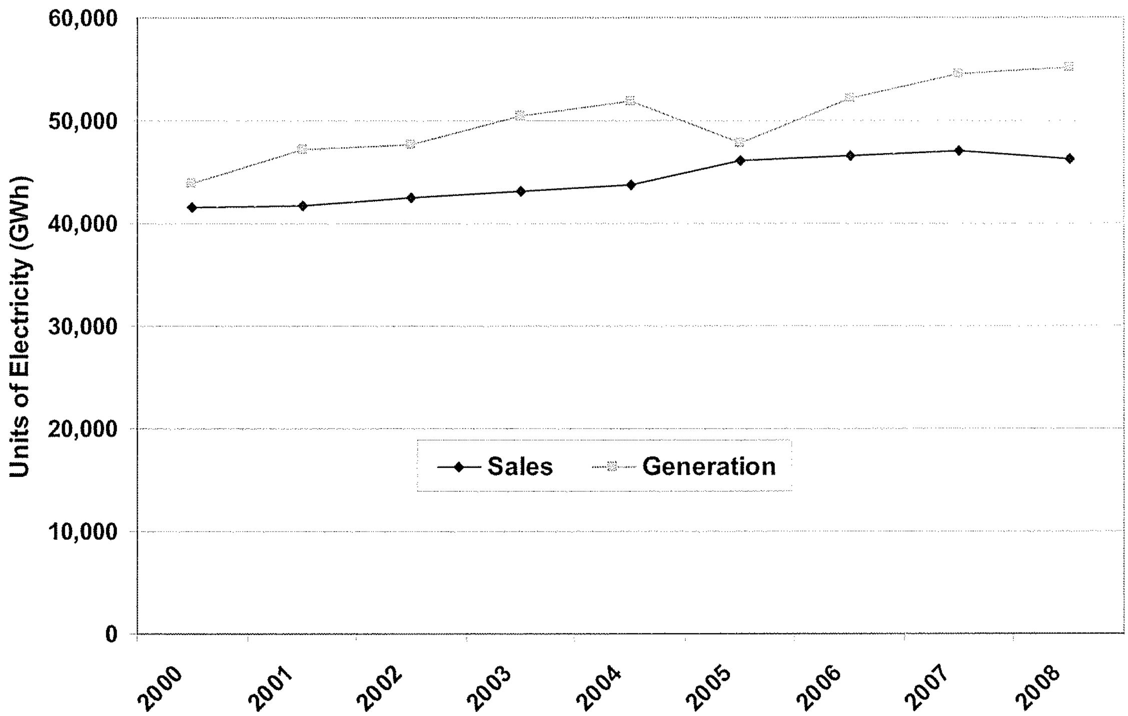
[2] Arkansas ranks 10th in the nation in terms of industrial sector electricity consumption as a percent of total consumption (EIA 2010b).

[3] Entergy is currently part of a cost-sharing Entergy System Agreement, approved by the Federal Energy Regulatory Commission (FERC) in 1985, with other Entergy utilities serving customers in Mississippi, Louisiana, New Orleans, and Texas. The System Agreement requires the achievement of "rough equalization" of total production costs across all the Entergy operating companies. The reliance of these utilities on coal, nuclear, oil, and natural gas for their fuel inputs means that production costs differ and exogenous shocks—particularly in the Gulf States—can have serious implications on those costs. By allowing the Entergy utilities to operate within a pool, the System Agreement requires those Entergy utilities with lower production costs to reimburse the other Entergy utilities—those relying on relatively more expensive fuel inputs like oil and natural gas—for their higher operating costs. The result is that Entergy Arkansas, which utilizes low-cost Western coal and nuclear power from mostly-amortized plants for electricity generation, has been paying the utilities in the Gulf States hundreds of millions of dollars per year over the last several years in order to maintain the "rough equalization" of production costs among the Entergy operating subsidiaries. Pursuant to the explicit terms of the System Agreement, Entergy Arkansas in 2005 gave the required eight years notice that it will exit the System Agreement in December 2013 (EAI 2010b). This notice has been recognized as valid by the FERC, which in November 2009 ruled that Entergy Arkansas would have no "continuing obligation" to participate in the System Agreement upon the expiration of the notice period. Louisiana is challenging this ruling in federal court. These intrasystem payments are not taken into account in Synapse's avoided cost analysis.

In 2008, Arkansas generated 55,000 GWh, yet consumed 46,000 GWh, making the state a net exporter of almost 16% of its electricity generation. Of the 46,000 GWh in sales, 37% were purchased by the industrial sector, and 38% and 25% were purchased by the residential and commercial sectors, respectively (EIA 2009). The majority of electricity generated in the state is produced by coal-fired power plants (47%), while nuclear power and natural gas generate 26% and 15% of Arkansas' electricity, respectively (see Figure 2-2).

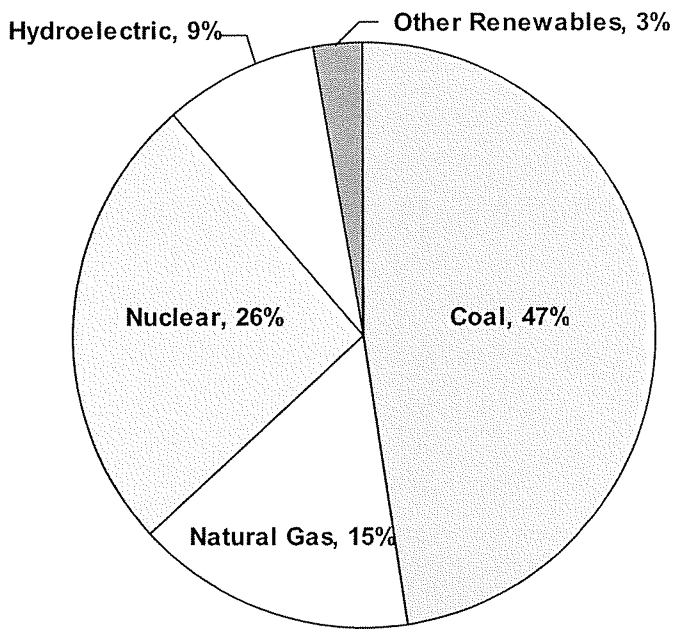
Arkansas delivers electricity to retail customers through three types of providers: IOUs, rural electric cooperatives, and municipal electric suppliers. As shown in Figure 2-3, 61% of electricity deliveries in Arkansas are from IOUs, with Entergy accounting for 46% of the Arkansas market. Arkansas' seventeen distribution cooperatives collectively account for 26% of the market, with municipal utilities and the remaining three IOUs following.

Figure 2-1. Electricity Consumption and Generation in Arkansas, 2000–2008



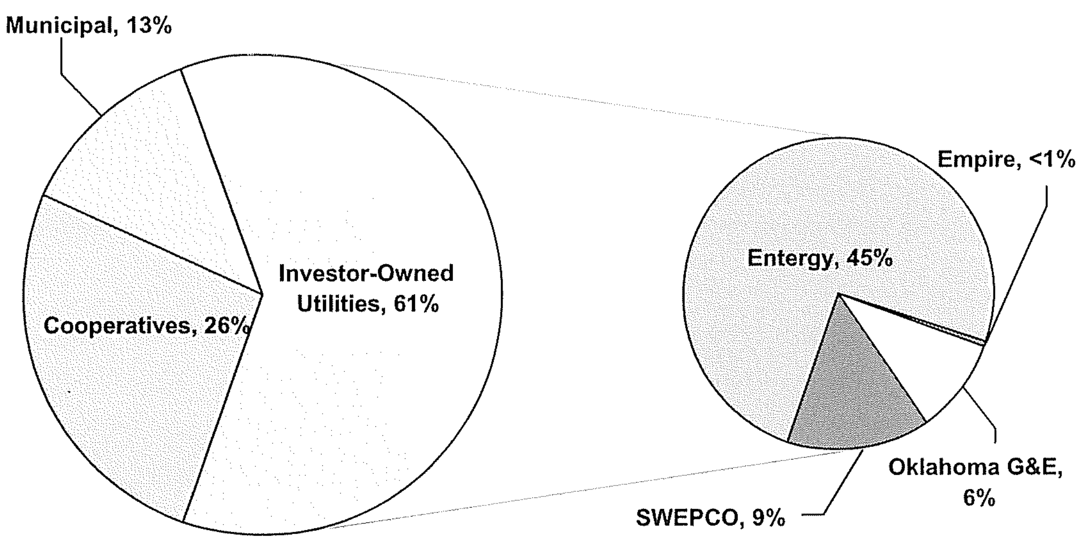
Source: EIA 2010a

Figure 2-2. 2007 Arkansas Electricity Generation by Fuel Type (Total Generation = 55,050 GWh)



Source: EIA 2010a

Figure 2-3. Electricity Deliveries by Supplier in 2008



Source: EIA 2010b

Utility-Level Projects

Despite the impact that energy efficiency can have on meeting energy demand growth in Arkansas, there will still be a need to update generation resources and transmission/distribution infrastructure in the future, especially as older generation units are retired and related infrastructure ages. While coal is the predominant fuel source for electricity generation, increasing costs of construction, lack of access to capital, potential federal climate legislation, and more stringent federal emissions regulations are making investments in coal-fired power plants less attractive. These variables, along with a decline in the annual growth of electricity demand across the state as a result of the recession, will heavily influence utilities' investment decisions, allowing them to consider deferring investments in generating capacity and instead focus on adopting and implementing aggressive energy efficiency programs.

Only one major baseload resource addition is planned in Arkansas over the next several years. The Southwestern Electric Power Company (SWEPCO) has already begun construction on its John W. Turk, Jr. 600 MW pulverized-coal plant in Hempstead County, for which it will retain a 73% share, or about 450 MW, at a total cost of over $2 billion. This plant is scheduled for completion by October 2012 (AEP 2009a, 2009b). Originally the plant was intended to come online in June 2011; however, the Arkansas Court of Appeals overturned PSC approval of the plant in June 2009, a decision that was reviewed by the Arkansas Supreme Court on April 15, 2010. On May 13, 2010, the Arkansas Supreme Court sided with the Court of Appeals in reversing the PSC decision, agreeing that the Commission violated state law by considering the need for the plant in a separate proceeding before considering whether or not to permit it. The case will be sent back to the PSC for a new proceeding in order to assess the need for the plant. In the meantime, construction of the plant is ongoing.

The Arkansas Electric Cooperatives Corporation (AECC) has a 12% stake in the John W. Turk plant, which will provide it with 71 MW of load upon completion. In its testimony filed with the PSC on May 9, 2008 regarding the Turk plant, the AECC noted that, taking into account trends in energy efficiency, its load is projected to grow at an average annual rate of 3% through 2020, roughly three times that of the rest of the state of Arkansas (Docket #08-084-U). To support this load growth, the AECC estimates the need for an additional 435 MW of capacity by 2020. According to its 2010 Resource Plan, in addition to its current owned and leased resources, the AECC has commitments to a 40 MW two-unit simple cycle gas plant (Elkins) that is under construction and expected to be in operation by the summer of 2010 (AECC 2010b). It is worth noting that while the AECC is not required to offer energy efficiency or demand response programs to its customers, it has been doing so for several decades and recently these programs have begun to ramp up considerably. In fact, its demand response programs are considered to be among the most robust compared to other cooperatives across the country (see Appendix D.5.1). However, it is unclear, either from the 2010 Resource Plan or from its annual energy efficiency reports filed with the PSC, exactly how much of its demand is being met by its energy efficiency programs.

Entergy's 2009 Integrated Resource Plan (IRP) assumes the addition of 1,500 MW of new capacity, fueled by gas-fired CCGT, with 500 MW of renewable generation resources added between 2014 and 2028. Entergy also assumes another 58 MW of nuclear capacity added through an upgrade at the Grand Gulf Nuclear Station, though the decision is not final. Otherwise, Entergy does not plan on adding new solid fuel or nuclear facilities over the next twenty years (EAI 2009). Oklahoma Gas & Electric estimates that its existing resource assets (along with additional wind, new energy efficiency programs, and smart grid demand response) will allow it to exceed its minimum 12% planning capacity margin until 2022.

Natural Gas

Natural gas is a significant source of energy in Arkansas and consumed across all sectors, although the industrial sector, including manufacturing and agriculture, consumes the majority of the state's natural gas supply, or 57% of total sales (151,000 million cubic feet [MCF] in 2007). However, Arkansas' natural gas utilities have been experiencing a decline in per-customer consumption in the residential sector over the last several years. It is worth noting that in one case declining customer usage was a result of sales volume growing more slowly relative to the increase in volume of its customers as opposed to declining trend in number of customers or sales.

Declining customer usage as well as other exogenous shocks that impact sales, such as abnormally warm winters, caused Arkansas' gas utilities to request approval from the PSC for a lost-revenue recovery mechanism, commonly referred to as decoupling. Known as the Billing Determinant Adjustment (BDA) mechanism in Arkansas, decoupling was approved by the PSC in 2007–08. We discuss decoupling and other lost-revenue recovery mechanisms in the section on our enabling policy recommendations.

Role of Energy Efficiency

Arkansas' efforts to advance energy efficiency are captured in ACEEE's *2010 State Energy Efficiency Scorecard* (Eldridge et al. 2009), which ranks states on ten energy efficiency policy and performance criteria. Arkansas claimed the 41st spot. The majority of Arkansas' points in our *2010 Scorecard* came as a result of stringent building codes and policies promoting combined heat and power, though its scoring relative to other states in these categories is indicative that there is still much more to be done, which we will discuss later on in this report. While Arkansas' ranking limited it to the bottom tier of states overall, the efforts of neighboring states are such that aggressive investments in energy efficiency could propel Arkansas towards the very top of the region.

In our energy efficiency policy analysis, we explore further opportunities to tap into the energy efficiency resource potential available in Arkansas. In leading states, for example, energy efficiency is meeting 1–2% of the state's electricity consumption and 0.5–1% of natural gas consumption each year (Nadel 2007; Hamilton 2008) at an average cost of about 2.5¢ per kWh (Friedrich et al. 2009), compared with a utility-avoided cost of about 3.5–10¢ per kWh in Arkansas (see Synapse's avoided cost analysis for Arkansas, below). Results from these states show that energy efficiency represents an immediate low cost, low risk strategy to help meet the state's future electricity needs (York, Kushler, and Witte 2008).

Arkansas' Current Utility Efficiency Programs

Arkansas' ranking in our *2009 Scorecard* indicates that, in general, the state has invested relatively little in energy efficiency and therefore has yet to realize any significant benefits. Prior to the release of 10 Orders regarding energy efficiency in December 2010, Arkansas had only relatively recently begun a concerted effort to implement energy efficiency programs over the last several years to rectify the lack of investment, albeit at modest levels to start. In 2007, the PSC adopted its Rules for Conservation and Energy Efficiency Programs to "begin a strong, statewide commitment to the legislative intent and directives of Arkansas' Energy Conservation and Endorsement Act" (PSC 2007).[4]

In 2007, the PSC ordered the state's electric and natural gas utilities to file "Quick Start" energy efficiency programs based on rules codified in the PSC's "Rules for Conservation and Efficiency Programs" (http://www.apscservices.info/rules.asp). Per the PSC order, the state and its electric and natural gas utilities have focused initially on the "low-hanging fruit," developing and implementing Quick Start efficiency programs that were filed with the PSC in July of 2007 and became effective in 2008.[5] Table 2-2 below presents savings and expenditures taken from the annual energy efficiency reports filed by all of Arkansas utilities for program years 2008 and 2009.

[4] Docket No. 06-004-U, Order No. 12 at 49. The final Energy Efficiency Rules are attached to Order No. 18 in that Docket.
[5] The initial filings of energy efficiency programs covered 2007–2009, though 2007 was a partial calendar year. Beginning April 1, 2009, each electric and gas utility was ordered to file a comprehensive set of program plans, for 2010 and later, that expanded upon the Quick Start programs.

Table 2-2. Savings, Expenditures and Performance Data on Utility Quick Start Energy Efficiency Programs

Expenditures (million$)	2008*		2009	
Electric Utilities	$6.24		$7.34	
NG Utilities	$1.05		$0.87	
Total	**$7.29**		**$8.21**	
Savings	**Elec./NG**	**MW**	**Elec./NG**	**MW**
Electric Utilities**	46.4 GWh	16.1	59.7 GWh	25.3
NG Utilities***	98.8 BBtu	NA	7.6 BBtu	NA
% of Annual Sales	**2008**		**2009**	
Electric Utilities	0.1%		0.13%	
NG Utilities	0.06%		0.005%	

* Two utilities did not disaggregate actual spending between the 2007 and 2008 program years, so this total does not reflect only spending in 2008. However, this also does not include aggregate expenditures in 2008 for the seventeen electric cooperatives, due to technical issues with the electronic document filed by AECC with the PSC on 3/31/2009.
** This does not include savings from the seventeen electric cooperatives, which are exempt from reporting on their energy efficiency programs. 2008 savings estimates also include estimated savings from the 2007 program year for one utility.
*** Savings in 2008 are considerably higher than in 2009 because of the relative success of Arkansas Western Gas' Commercial/Industrial (C/I) Natural Gas Energy Audit program, where implementation of recommendations in the C/I audits were reported to total 91,692 hundred cubic feet (CCF), or about 94 BBtu. 2008 savings estimates include estimated savings from the 2007 program year for two utilities.

Between 2007–09, Arkansas' electric and natural gas utilities collectively participated and assisted in the administration of two statewide Quick Start efficiency programs: the Arkansas Weatherization Program (AWP), which is aimed at retrofitting homes that are deemed "severely inefficient" and is jointly administered by utilities, the Arkansas Community Action Agencies Association (ACAAA), and the Arkansas Department of Health and Human Services Office of Community Services; and Energy Efficiency Arkansas (EEA), a statewide education program jointly administered by utilities and the Arkansas Energy Office. Each electric utility has established several additional energy efficiency programs that offer services across the residential, commercial, and industrial sectors. As noted earlier, on February 3, 2010, the PSC began the transition toward comprehensive energy efficiency programs with its approval of the utilities' energy efficiency program proposals for an 18-month period for the 2010 program year. With the comprehensive phase set to begin, utilities are required to file their 2011 programs and budgets by April 1, 2011.

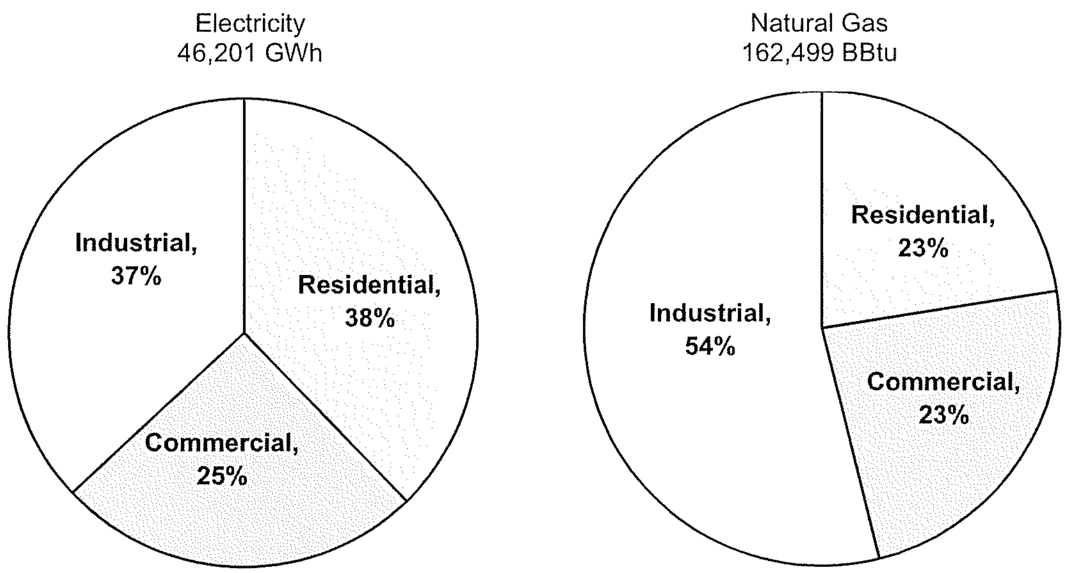
During the Quick Start phase, Arkansas' three natural gas utilities each filed identical plans for the implementation of four efficiency programs, two of which include funding and participation in the jointly-administered AWP and EEA programs. The other two programs consisted of commercial/industrial energy audits and utility-specific customer education initiatives. In the comprehensive phase, the PSC has approved similar commercial and industrial energy efficiency rebate programs for gas utilities, beginning in 2010.

The Arkansas General Assembly has also taken some initiative, passing Act 1494 in April of 2009. The new law requires 10% energy reductions in new construction of state facilities and calls for the AEO to develop and implement plans to reduce energy consumption in existing state buildings by 20% by 2014 and 30% by 2017. Government buildings in Arkansas represent almost 8% of commercial building electricity use in the state and around 9% of commercial building natural gas use, or about 950 GWh and 3,300 BBtu annually. The *American Recovery and Reinvestment Act*, through the State Energy Program, allocated $40 million to the AEO that it is investing in thirteen projects, which include an energy efficiency outreach program, an online industry clearinghouse, and training centers for auditors and contractors.[6]

Reference Case

This section describes Arkansas' current and projected energy consumption under a business-as-usual scenario by sector for electricity and natural gas. Current statewide consumption values are based on data from the Energy Information Administration (EIA) by end-use sector (see Figure 2-4), which takes into account savings from existing federal appliance standards, such as the standards passed in the *Energy Independence and Security Act* (EISA) of 2007. Ideally, our consumption forecasts are a summation of individual utility forecasts, but sales forecasts for the individual electricity and natural gas utilities in Arkansas were unavailable. Thus our forecasts were derived from a variety of sources, including Entergy's (EAI) IRP and the EIA's *Annual Energy Outlook*. Both the electric and natural gas forecasts were adjusted to take into account savings from future federal appliance standards, which are based on ACEEE estimates.

Figure 2-4. 2008 Energy Consumption in Arkansas by End-Use Sector



Modified Reference Case

Forecasts often do not account for reduced consumption that arises from energy efficiency and demand response programs initiated by utilities, nor do they account for energy savings from consumers' purchase of more efficient appliances and equipment. These savings should not be ignored as their accumulation lessens the burden of achieving any state-mandated savings target, such as an energy efficiency resource standard. While Arkansas has not implemented its own appliance efficiency standards, the U.S. Department of Energy (DOE) is actively developing and mandating standards and is scheduled to implement standards on over two dozen products by 2013.[7] The following section provides

[6] For more information on the Arkansas Energy Office's plans for investing the funds allocated to it through the State Energy Program grant, please visit: http://arkansasenergy.org/energy-in-arkansas/energy-policy-and-legislation/recovery-2009/state-energy-program.aspx.

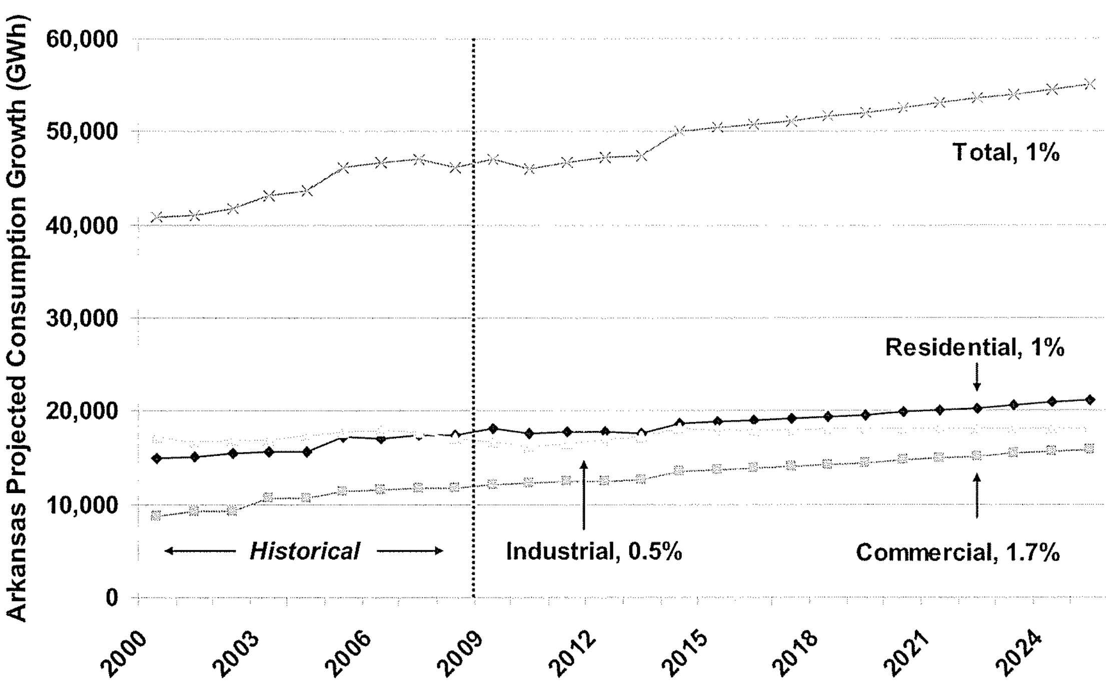
[7] The DOE is scheduled to implement new federal appliance and equipment standards, as well as update current standards, for 26 products between 2009 and 2013. Included are standards for fluorescent and incandescent reflector lamps, central air conditioners

greater detail about our "modified" reference case, which is our consumption forecast net any savings accumulated through utility efficiency programs and federal appliance standards. We use the modified reference case as the base case consumption forecast through which we analyze the percent savings of the individual policies and utility programs.

Electricity (GWh) and Peak Demand (MW)

Arkansas' forecast of electricity consumption uses 2008-year actual sales reported to the Energy Information Administration as a baseline (EIA 2010b). The EIA's *Annual Energy Outlook* forecasts electricity consumption by sector and by region, while its *Electric Power Annual* provides historical consumption data. But regional data does not necessarily reflect trends that are unique to a state. Fortunately, ACEEE did not need to rely on regional data to develop the reference case forecast. For Arkansas, Synapse Energy Economics, Inc. (Synapse) estimated ACEEE's statewide sales forecast for electricity using load growth rates from Entergy's 2009 IRP as a proxy for growth in state sales. Using this methodology, and accounting for savings from future federal appliance standards, we estimate that total electricity consumption in the state will grow at an average annual rate of 1% between 2009 and 2025, and 1%, 1.7%, 0.5% in the residential, commercial, and industrial sectors, respectively (see Figure 2-5). Actual electricity consumption in 2008 according to the 2008 *Electric Power Annual* was 46,201 GWh, growing to 50,401 GWh in 2015 and 55,043 GWh in 2025 (see Appendix A for more detail on our methodology).

Figure 2-5. Arkansas Electricity Consumption, Historical and Forecasted, 2000–2025



Synapse utilized the sales forecast above and historical data from the EIA on average loss factor (13.36%) to estimate system peak demand for the state of Arkansas (see Figure 2-6). Taking the sales

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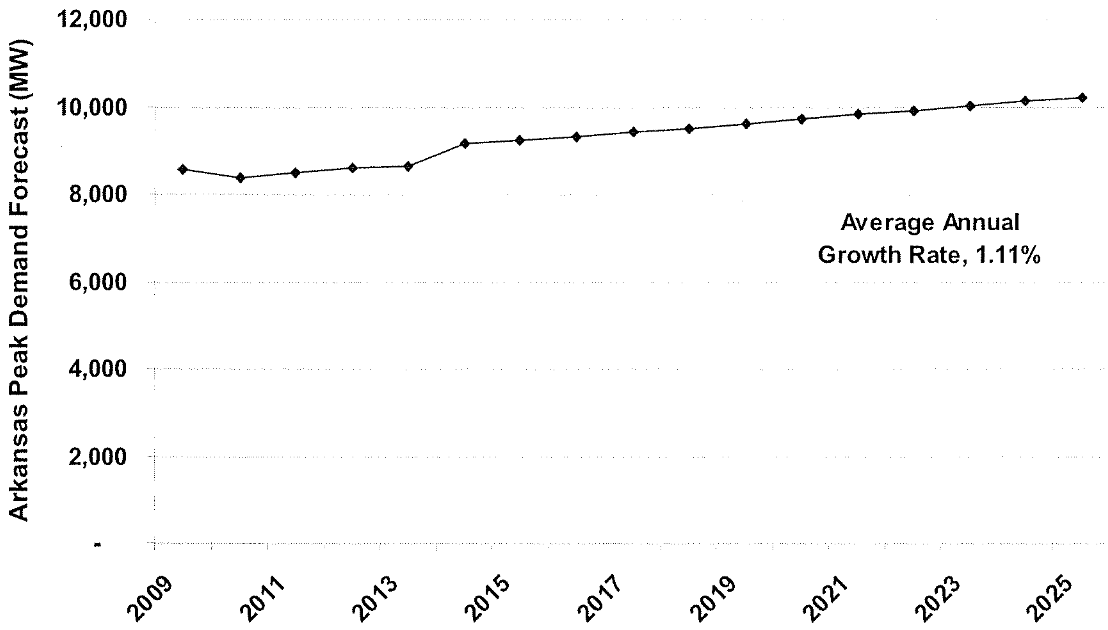
and heat pumps, furnace fans, and residential water heaters, which represent some of the most energy-intensive appliances and equipment on the market. The analysis of the potential savings of these standards can be found in the Appliance Standards Awareness Project (ASAP) and ACEEE report entitled *Ka-Boom! The Power of Appliance Standards: Opportunities for New Federal Appliance and Equipment Standards* (Neubauer et al. 2009).

forecast and adjusting for system losses, Synapse estimated an overall energy load. An assumed load factor of 62.7% was then applied to the estimates of Arkansas' energy load to determine system peak demand. Using this methodology, we estimate that peak demand in Arkansas will grow at an average annual rate of 1.11% between 2009 and 2025, reaching around 9,200 MW in 2015 and 10,200 MW in 2025.

Figure 2-6. Arkansas Peak Demand Forecast, 2009–2025

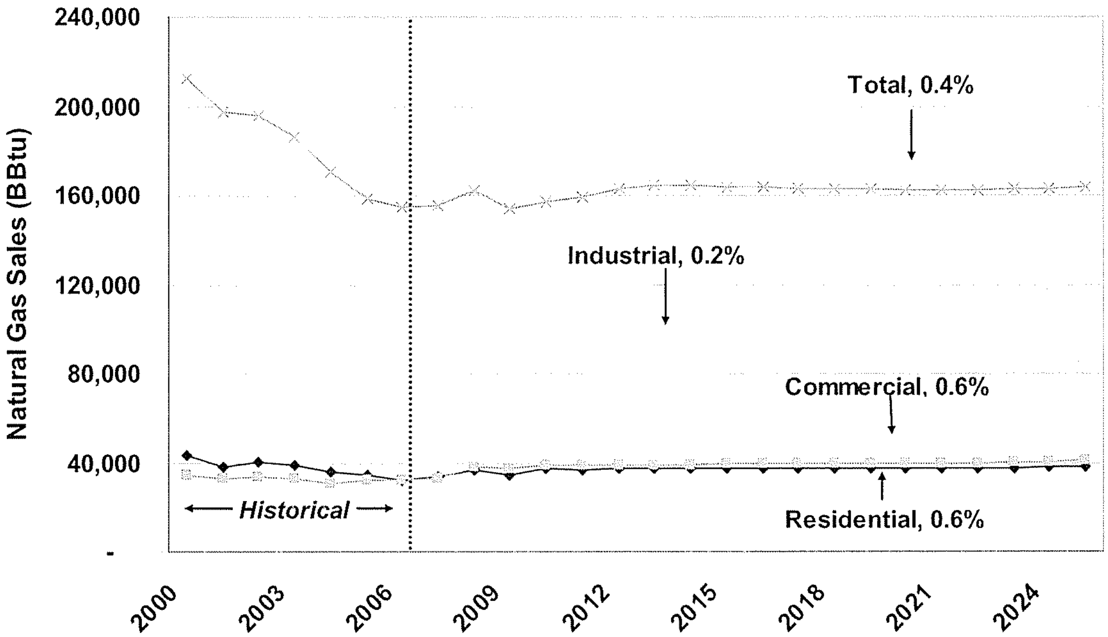


Natural Gas (BBtu)

ACEEE's forecast for natural gas consumption in Arkansas is based upon historical consumption data provided by the EIA's *Natural Gas Navigator*. To estimate projected consumption, we applied annual growth rates derived from the 2009 *Annual Energy Outlook* forecast for the West South Central region to state-specific historical data take from the Natural Gas Navigator (EIA 2010d). We then deducted estimated savings from federal appliance standards to generate our modified reference case.[8] Using this methodology, we estimate that total natural gas consumption in the state will grow at an average annual rate of 0.4% between 2009 and 2025, and 0.6%, 0.6%, and 0.2% in the residential, commercial, and industrial sectors, respectively (see Figure 2-7).

[8] By 2025, federal appliance standards will reduce natural gas consumption by 0.8% relative to projected consumption.

Figure 2-7. Arkansas Natural Gas Consumption, Historical and Forecasted, 2000–2025



Utility-Avoided Costs

Synapse developed high-level projections of utility production and avoided marginal costs for use in our policy analysis. These costs are important because they reflect the reduced cost to utilities from avoided electricity generation as a result of energy efficiency. ACEEE used these results to estimate the cost-effectiveness of energy efficiency measures and assess the macroeconomic impacts. Readers should note that the avoided cost estimates are based upon a number of simplifying and conservative assumptions. These simplifications include use of a single annual average avoided energy cost to evaluate the economics of energy efficiency measures rather than different avoided energy costs for energy efficiency measures with different load shapes.

Synapse's analysis also assumed a cost of carbon, which would impact avoided costs in the sense that it represents additional operating costs to fossil fuel generation plants. Through the examination of reports conducted by over a dozen federal, academic, and non-governmental organizations, Synapse was able to ascertain the factors influencing allowance prices and estimate three forecasts: a low, middle, and high case. For this report, Synapse used their middle case, which estimates a base-level cost of carbon at $15/ton starting in 2013, increasing to around $54/ton by 2030 (Schlissel et al. 2008).

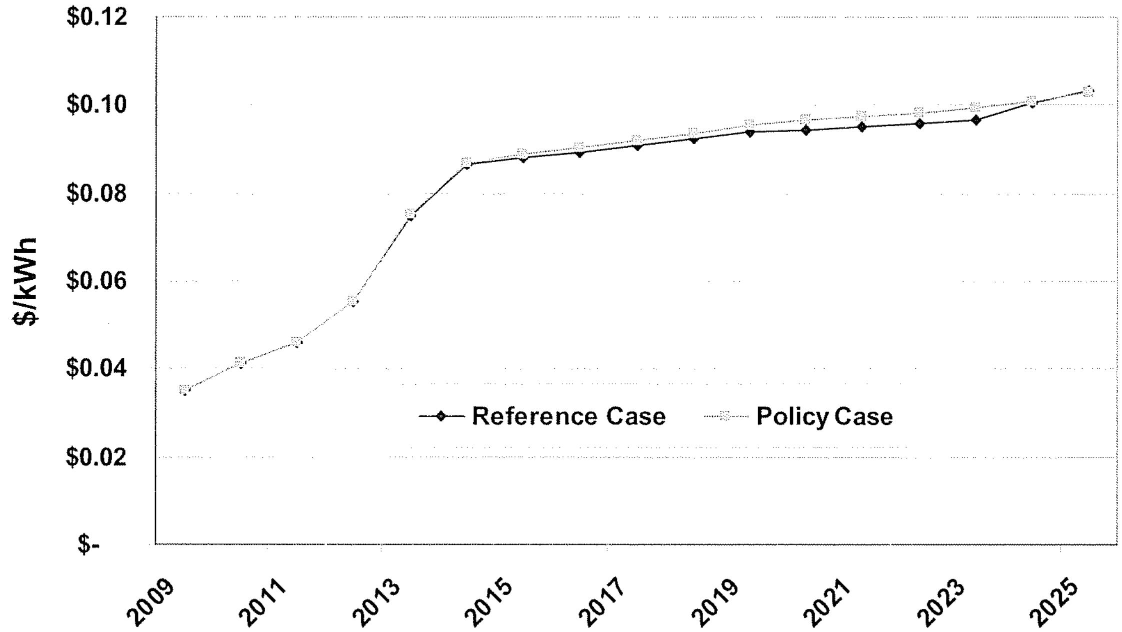
Implications of the Avoided Cost Assumptions

Because the level of energy efficiency and demand response measures assessed in this study significantly change the requirements of future resources, we developed two sets of production and avoided costs projections with which to measure the potential savings. The first case reflects the market conditions that would be anticipated in the modified reference case. The second case, or the policy case, reflects the impacts of our policy recommendations, which we discuss later on in this report. These policy recommendations have the potential to generate significant electricity savings, which, as mentioned above, will change the composition of utilities' future generation resources. Unfortunately, it is virtually impossible to predict how the generation mix will change, but we are required to make assumptions about this mix in order to estimate avoided costs in the policy case. Assumptions of the composition of generation resources are taken from the individual utility integrated resource plans filed with the PSC.

Estimates of Avoided Costs

The policy case produced modestly higher avoided resource costs than the reference case for the majority of the analysis period, as can be seen in Figure 2-8. As a further conservative measure in our analysis, we used the first, lower set of costs in valuing the savings that result from the analyzed policies and programs. A detailed discussion of the assumptions and avoided cost estimates can be found in Appendix A.

Figure 2-8. Estimates of Average Annual Avoided Resource Costs



Retail Price Forecast

ACEEE also developed a possible scenario for retail electricity and natural gas prices in our modified reference case. Readers should note the important caveat that we do not intend to project future energy prices in Arkansas precisely for either the short or the long term. Rather, our goal is to suggest a possible scenario, based on data from credible sources, and to use that scenario to estimate impacts from energy efficiency on electricity customers in Arkansas.

Table 2-3 shows 2007 electricity prices in Arkansas (EIA 2008a) and our estimates of retail rates by customer class over the study period. This price scenario is based on two key factors. First, we use the average generation cost of electricity in Arkansas over the study period as calculated by Synapse Energy Economics. Next, we use estimates of retail rate adders (the difference between generation costs and retail rates, which accounts for transmission and distribution costs) from the *Annual Energy Outlook* for the Southeastern Electric Reliability Council (SERC) (EIA 2009).

Table 2-3. Retail Electricity Price Forecast Scenario in Reference Case (cents per kWh in 2007$)

	2007	2010	2015	2020	2025	Average
Residential	8.2	8.1	9.7	10.4	11.2	**9.7**
Commercial	6.9	7.0	8.4	9.1	9.8	**8.4**
Industrial	5.1	4.9	6.4	6.9	7.7	**6.3**
All Sector Average	**6.8**	**6.8**	**8.4**	**9.0**	**9.8**	**8.3**

Note: These figures are in real, 2007-year dollars and therefore do not take into account inflation.

ACEEE also developed a possible scenario for retail natural gas prices in the reference case, shown in Table 2-4. Retail Natural Gas Price Forecast Scenario in Reference Case. We used long-term Henry Hub estimates developed by Synapse Energy Economics and then used estimates of retail rate adders (the current difference between Henry Hub and retail prices) to develop a retail price scenario. Based on this analysis our scenario consisted of average natural gas prices of about $8–11 per million Btu to consumers in Arkansas over the 2009–2025 study time period.

Table 2-4. Retail Natural Gas Price Forecast Scenario in Reference Case

	2007	**2010**	**2015**	**2020**	**2025**	**Average**
Residential	12.7	10.8	11.0	11.6	12.3	**11.4**
Commercial	9.8	8.2	8.4	9.0	9.7	**8.8**
Industrial	9.2	7.6	7.8	8.3	9.1	**8.2**

Note: These figures are in real, 2007-year dollars and therefore do not take into account inflation.

Chapter Three: Energy Efficiency Cost-Effective Resource Assessment

This section presents the results from our assessment of cost-effective energy efficiency resources in residential and commercial buildings, the industrial sector, and combined heat and power, and is used to paint a picture of the potential savings that could be captured by the policy recommendations we discuss later in the report. Cost-effectiveness of more efficient technologies, compared to a standard baseline technology, is determined from the customer's perspective, i.e., a measure is deemed cost-effective if its levelized[9] cost of conserved energy (CCE) is less than the average retail energy price for a given customer class. Average CCEs for each sector are given in the following sections. Table 3-1 presents a summary of energy efficiency potential by sector in 2025. Readers should note that this assessment includes mostly existing technologies and practices, though we anticipate that new and emerging technologies and market learning will increase the volume of cost-effective energy resources by 2025.

Table 3-1. Summary of Cost-Effective Energy Efficiency Potential by Sector (2025)

Sector	Electricity		Natural Gas	
	GWh	%*	BBtu	%*
Residential**	NA	NA	31,000	28%
Commercial (non-CHP)	4,700	9%	12,800	8%
Industrial (non-CHP)	2,900	5%	13,200	8%
Combined Heat & Power	240	<1%	NA	NA

*Savings are represented as a percent of the total projected energy consumption in 2025.
**The Building Model, TREAT, used for the residential analysis estimates values only in terms of Btus. We converted projected electricity consumption in the residential sector from GWh to BBtus to determine the percent savings for both electricity and natural gas, so the residential savings values represent both electric and natural gas savings as a percent of projected electricity and natural gas consumption in 2025.

Residential

For our analysis of energy efficiency potential for Arkansas' residential sector, we used a residential building energy modeling software package, TREAT, to compute the average baseline Arkansas home, and the potential energy savings available (see Appendix B for details on the methodology). The baseline home was computed using a variety of housing characteristics gathered from local utilities and national datasets. First, we input these housing characteristics into TREAT to model a typical home (see Appendix B for these characteristics). Table 3-2 shows the baseline energy use (a combination of gas & electricity) for a typical Arkansas home.

Table 3-2. Baseline Single Family Home Energy Use in Arkansas

End-Use	Average Fuel Used (MMBtu)
Heating	43.8
Cooling	12.3
Hot water	27.3
Lighting	6.5
Appliances & Electronics	34.6
Total	**124.5**

[9] Levelized cost is the level of payment necessary each year to recover the total investment over the life of the energy efficiency measure.

We evaluated 18 efficiency measures that can be adopted in existing and new single family residential homes based on the overall cost-effectiveness of the combined measures. An upgrade to a new measure is considered cost-effective if its levelized cost of conserved energy is less than 8.23 cents per kWh, or $13.77/MMBtu for gas, the regional residential prices for energy (EIA 2008a, 2010d); in other words, if it is cheaper to pay to save a unit of energy than to pay to use that energy. Because of the nature of the modeling software used, we could not disaggregate the gas and electric savings potential for each measure. Therefore we analyze all measures in Btu's.[10] The average retail cost of electricity in Arkansas is $24.11/MMBtu; because we cannot disaggregate the measures, we look for measures that cost less per unit than both electricity and gas. For the measures we analyzed, the average levelized cost per measure was $5.76/MMBtu. Table 3-3 outlines the measures analyzed and their savings potential.

Table 3-3. Single Family Residential Energy Efficiency Potential and Costs by End-Use in Arkansas

End-Use	Savings (BBtu)	Savings %	% of Efficiency Potential	Levelized Cost of Saved Energy ($/MMBtu saved)
HVAC Shell	6,925	8%	22%	$ 4.20
HVAC Equipment	7,879	9%	25%	$ 3.61
Water Heating	4,227	5%	14%	$ 7.39
Lighting	553	1%	2%	$ (3.02)
Refrigeration	1,934	2%	6%	$ 1.01
Appliances	4,917	6%	16%	$ 2.58
Plug Loads	126	0%	0%	$ -
Existing Homes	*26,561*	*31%*	*86%*	*$ 6.02*
New Homes	*4,496*	*5%*	*14%*	*$ 4.20*
Total energy	**31,057**	**37%**	**100%**	**$ 5.76**

For single family houses, we estimated a statewide economic potential for efficiency resources of 31,057 BBtu in the residential sector over the 17 year period of 2009–2025, a potential savings of 37% of the reference case electricity consumption in 2025 (see Table 3-3).

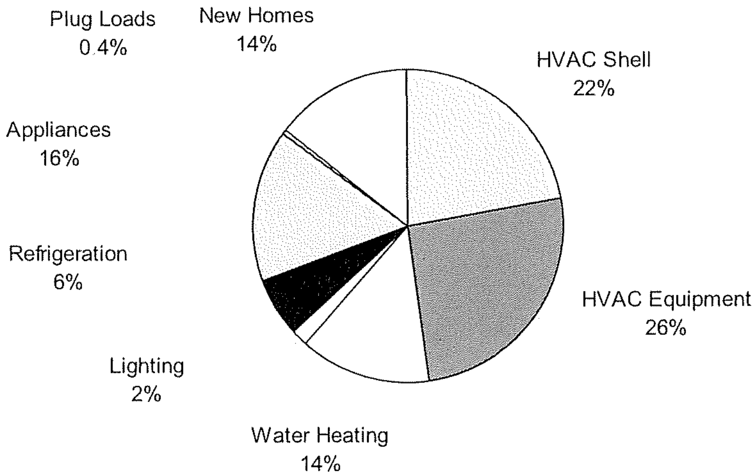
In the residential sector, the majority of savings potential can be realized through improved housing shell performance (e.g., insulation measures, duct improvements, reduced air infiltration, and ENERGY STAR windows) and more efficient heating, ventilating, and air conditioning (HVAC) equipment and systems. These categories account for nearly half of the potential savings.

Water heating, refrigeration, and other appliances can also contribute substantial savings potential. Water heating constitutes 14% of potential savings (see Table 3-3). Measures to reduce hot water load include low-flow showerheads and faucet aerators. More efficient water heaters, including more efficient electric water heaters and condensing gas water heaters, can substantially contribute to energy savings. Additional savings are garnered through more efficient water-using appliances, such as dishwashers and clothes washers (in our analysis these savings are grouped with appliances, not water heaters).

Simply replacing refrigerators and freezers with ENERGY STAR models (in top-freezer configurations in the case of refrigerators) would account for 6% of overall residential energy savings. Other more efficient versions of appliances that contribute to energy savings include clothes washers, dishwashers, and televisions. Altogether these three appliances account for 16% of total energy savings potential (see Figure 3-1).

[10] British Thermal Units.100,000 Btu = 29.3 kWh = 1 Therm

Figure 3-1. Residential Energy Efficiency Potential in 2025 by End-Use in Arkansas
Total: 31,000 BBtu
37% of Projected Energy Consumption in 2025



Commercial

Electricity

The potential for electricity savings through energy efficiency for the commercial sector in Arkansas is examined through a scenario of 33 cost-effective measures for electricity savings that would be adopted during the 17-year period from 2008 to 2025. An upgrade to a new measure is considered cost-effective if its levelized cost of conserved energy is less than 6.8 cents/kWh saved, which is the average retail electricity price for the commercial sector in Arkansas over the study time period (EIA 2008a). For the sum of all measures, the estimated levelized cost is 2.0 cents/kWh saved (Table 3-4). See Appendix B for a detailed methodology and specific efficiency opportunities and cost-effectiveness for commercial buildings (see Table B-7).

Table 3-4. Commercial Electricity Potential and Costs by End-Use in Arkansas

End-Use	Savings (GWh)	Savings over Reference Case (%)	% of Efficiency Potential	Weighted Levelized Cost of Saved Energy ($/kWh)
HVAC and Building Shell	1,352	8.5%	31%	$ 0.029
Water Heating	24	< 1%	1%	$ 0.033
Refrigeration	257	2%	6%	$ 0.017
Lighting	1,338	8.5%	31%	$ 0.016
Office Equipment	452	3%	11%	$ 0.003
Appliances and Other	5	< 1%	< 1%	$ 0.030
Existing Buildings	*3,428*	*21%*	*80%*	*$ 0.022*
New Buildings	*875*	*6%*	*20%*	*$ 0.013*
Total Electricity	**4,303**	**27%**	**100%**	**$ 0.020**

Commercial buildings can reduce electricity consumption by 27% through the adoption of a variety of efficiency measures. The economic potential for efficiency resources in the commercial sector will reduce electricity use by 4,300 GWh through the period 2009–2025.

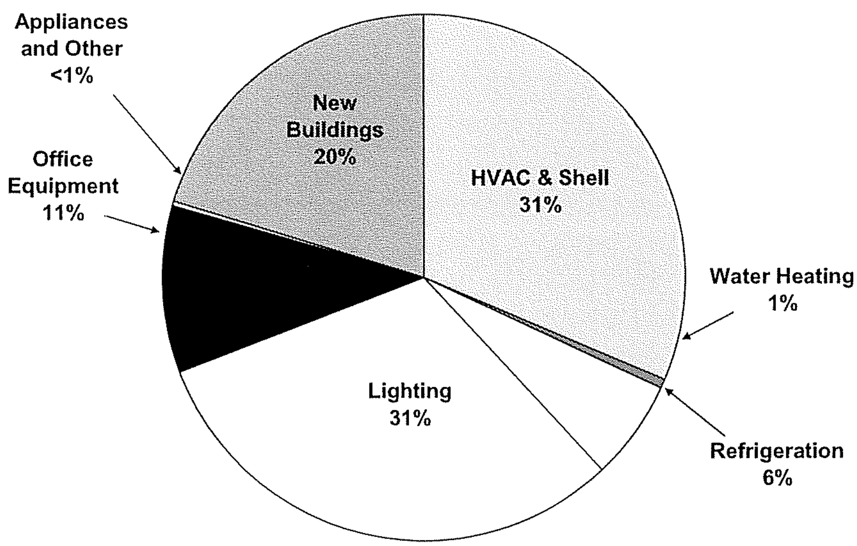
In the commercial sector, electricity savings from efficiency resources are realized through improved HVAC equipment, controls, and building shell measures (e.g., roof insulation and new windows); improved water heating (e.g., heat pump water heaters); more efficient refrigeration systems (e.g., ENERGY STAR vending machines and coolers); and efficient lighting, office equipment, and miscellaneous appliances. The greatest portion of the savings, at 31%, is from improvements to the building shell and HVAC system. Shell measures include roof insulation and improved windows. HVAC measures include better heating and cooling systems (e.g., high efficiency chillers and heat pumps) and better controls (e.g., dual enthalpy controls and energy management system installations).

Lighting efficiency also generates substantial savings, accounting for 31% of the total savings potential, which includes savings from more efficient light bulbs such as fluorescent and HID, improved lighting controls such as daylight dimming systems and occupancy sensors, and certain LED applications such as task lighting. Office equipment measures can provide another 11% savings with measures including more efficient computers, printers, and copiers, etc., as well as turning off this equipment after hours.

Water heating measures include heat pump water heaters, and efficient clothes washers that reduce hot water demand. Refrigeration measures include improved commercial refrigeration systems (e.g., walk-in coolers, ice makers, and vending machines).

New construction measures contribute a significant portion of the overall savings potential for the commercial sector, reaching 20% of total electric savings (see Figure 3-2). We estimate that up to 50% savings can be reached cost-effectively for commercial new construction (NREL 2008).

Figure 3-2. Commercial Electric Efficiency Potential in 2025 by End-Use in Arkansas
Total: 4,300 GWh
27% of Projected Electricity Use in 2025



Natural Gas

The potential for natural gas savings through energy efficiency in Arkansas's commercial building sector is examined through a scenario of 23 cost-effective measures for gas savings that would be adopted during the 17-year period from 2009 to 2025. An upgrade to a new measure is considered cost-effective if its levelized cost of conserved energy is less than $11.08/MMBtu saved, which is the average retail natural gas price in Arkansas over the study time period in the reference case price forecast (EIA 2008a). For the sum of all measures, the estimated levelized cost is $3.43/MMBtu saved (see Table 3-5). See Appendix B for a detailed methodology and specific efficiency opportunities and cost-effectiveness for commercial buildings (see Table B-10).

Table 3-5. Commercial Natural Gas Efficiency Potential and Costs by End-Use in Arkansas

End-Use	Savings (BBtu)	Savings over Reference Case (%)	% of Efficiency Potential	Weighted Levelized Cost of Saved Energy ($/MMBtu)
HVAC Equipment & Controls	6,629	16%	52%	$ 2.70
Building Shell	293	1%	2%	$ 0.20
Water Heating	698	2%	5%	$ 3.40
Cooking	893	2%	7%	$ 6.04
Other	974	2%	8%	$ 7.90
Existing Buildings	*9,489*	*23%*	*74%*	*$ 3.65*
New Buildings	*3,321*	*8%*	*26%*	*$ 3.86*
Total Gas	**12,811**	**31%**	**100%**	**$ 3.43**

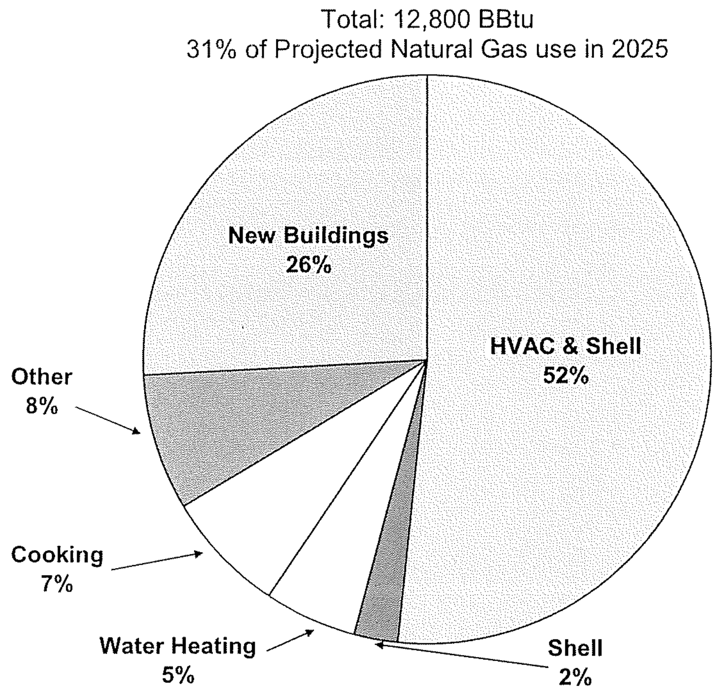
Commercial buildings can reduce natural gas consumption by 31% through the adoption of a variety of efficiency measures. The economic potential for efficiency resources in the commercial sector will reduce natural gas use by over 12 trillion Btu through the period 2009–2025.

In the commercial sector, gas savings from efficiency resources are realized through improved HVAC equipment, controls and building shell measures (e.g., duct sealing and pipe insulation); improved water heating (e.g., tankless water heaters); and more efficient cooking equipment (e.g., ENERGY STAR fryers). The majority of the savings is provided by improved HVAC measures, including heating system measures, and improved controls, which provide 52% of the total gas savings potential. Our calculations for improved heating equipment take into account the different types of equipment that are appropriate for different size buildings, and include furnaces, rooftop units, and boilers. Improved controls include programmable thermostat and energy management systems. Building shell measures include roof insulation and low-e windows.

Improved water heating and cooking appliances provide additional significant savings, with 5% and 7% of the total gas savings potential, respectively. Gas condensing water heaters contribute the vast majority of water heating savings with over 600 BBtu savings potential. For cooking measures, high efficiency convection range/ovens and ENERGY STAR fryers provide the largest amount of savings.

New construction measures contribute a significant portion of the overall savings potential for the commercial sector, totaling 26% of natural gas savings (see Figure 3-3). We estimate that up to 50% savings can be reached cost-effectively for commercial new construction (NREL 2008).

Figure 3-3. Commercial Natural Gas Efficiency Potential in 2025 by End-Use in Arkansas



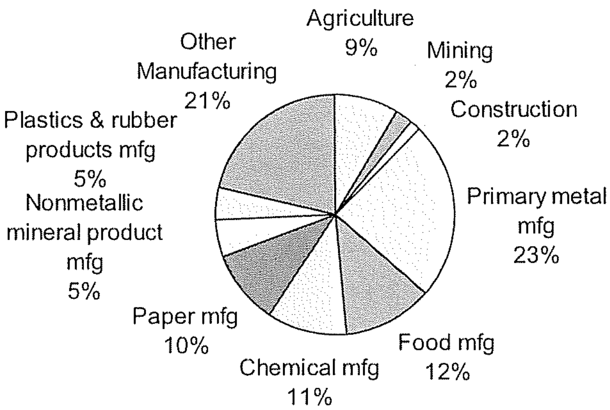
Industrial

The industrial sector is the most diverse economic sector, encompassing agriculture, mining, construction and manufacturing. Because energy use and efficiency opportunities vary by individual industry (if not individual facility), it is important to develop a disaggregated forecast of industrial electricity and natural gas consumption. Unfortunately, this energy use data is not available at the state level, so ACEEE has developed a method using state-level economic data to estimate disaggregated electricity and natural gas use. This study drew upon national industry data to develop a disaggregated forecast of economic activity for the sector. We then applied energy intensities derived from industry group electricity consumption data reported and the value of shipments data to characterize each sub-sector's share of the industrial sector electricity consumption and projected the energy use through 2025

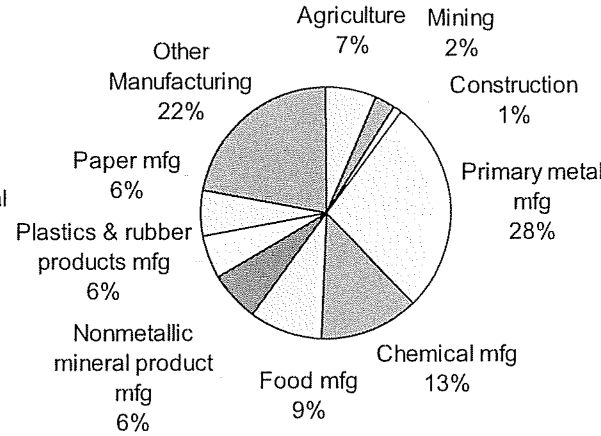
Figure 3-4 shows the largest electricity consuming industries in Arkansas in 2008 and 2025.

Figure 3-4. Estimated Electricity Consumption for the Largest Consuming Industries in Arkansas in 2008 and 2025

2008 Electricity Consumption By Industry



2025 Electricity Consumption By Industry

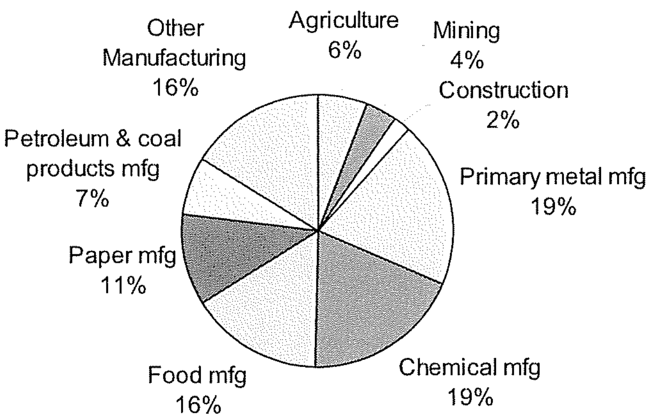


Due to changes in economic activity and energy intensity as discussed in Appendix B, we see some intra-sectoral shifts in electricity consumption. For the agricultural sector, mild economic growth means its electricity usage will grow more slowly than industry at large. Similarly, significant economic growth in primary metal manufacturing will lead to it accounting for a larger share of industrial electricity use. Food and paper manufacturing will have lower shares of industrial electricity use by 2025, due to mild and negative growth, respectively. These intra-sectoral shifts are important because they identify where new investments are being made and where energy efficiency opportunities are concentrated.

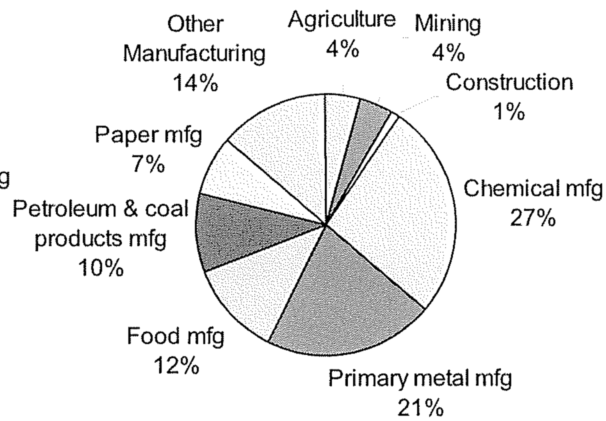
Figure 3-5 shows the largest natural gas consuming industries in Arkansas in 2008 and 2025.

Figure 3-5. Estimated Natural Gas Consumption for the Largest Consuming Industries in Arkansas in 2008 and 2025

2008 NG Consumption By Industry



2025 NG Consumption By Industry



Similar changes in economic activity and energy intensity cause significant intra-sectoral shifts in natural gas consumption. While chemical manufacturing will see moderate growth in electricity use, it will see a significant increase in natural gas consumption, growing from 19% of industrial natural gas use to 27%.

This is caused by projections of both a significant increase in economic activity and a moderate increase in energy intensity. As with the trends in electricity usage, the food and paper manufacturing industries will account for a smaller share of industrial natural gas use. Primary metal manufacturing will account for a higher portion of natural gas use, but will fall from the number one position. Petroleum & coal manufacturing will also see a significant increase in natural gas consumption. These intra-sectoral shifts are important because they identify where new investments are being made and where energy efficiency opportunities are concentrated.

Electricity

We examined 18 electricity saving measures, 10 of which were cost effective considering Arkansas' average industrial electric rate of $0.063/kWh. These measures were applied to an industry specific end-use electricity breakdown. Table 3-6 shows results for industrial energy efficiency potential by 2025.

Table 3-6. Industrial Electric Efficiency Potential and Costs by End-Use in Arkansas

Measures	Savings Potential in 2025 (GWh)	Savings Potential in 2025 (%)	% of Efficiency Potential	Levelized Cost of Saved Energy ($/kWh)
Sensors & Controls	73	0.4%	3%	$0.014
EIS	23	0.1%	1%	$0.061
Duct/Pipe insulation	592	3.3%	21%	$0.052
Electric Supply	542	3.0%	19%	$0.010
Lighting	214	1.2%	7%	$0.020
Motors	686	3.8%	24%	$0.027
Compressed Air	218	1.2%	8%	$0.000
Pumps	404	2.2%	14%	$0.008
Fans	78	0.4%	3%	$0.024
Refrigeration	53	0.3%	2%	$0.003
Total	**2,882**	**16%**	**100%**	**$0.023**

This analysis found economic savings from these cross-cutting measures of 2,882 million kWh or 16% of industrial electricity use in 2025 at a levelized cost of about $0.02/kWh saved. This analysis did not consider process-specific efficiency measures that would be applied at the individual site level because available time, funding, and data did not allow this level of analysis. However, based on experience from site assessments by the U.S. Department of Energy and other entities, we would anticipate an additional economic savings of 5–10%, primarily at large energy-intensive manufacturing facilities. The overall economic industrial efficiency resource opportunity is on the order of 21–26%. Therefore, the total economic potential for electricity savings in the industrial sector in 2025 would be about 4,243 GWh.

Natural Gas

We examined 36 natural gas saving measures, 33 of which were cost effective considering Arkansas' average industrial natural gas rate of $8.21/MMBtu. These measures were applied to an industry specific end-use natural gas breakdown.

Table 3-7 shows summarized results for industrial natural gas efficiency potential by 2025. A full measure list can be found in Appendix C.

Table 3-7. Industrial Natural Gas Efficiency Potential and Costs by End-Use

Measures	Savings Potential in 2025 (BBtu)	Savings Potential in 2025 (%)	% of Efficiency Potential	Levelized Cost of Saved Energy ($/MMBtu)
Improved Boiler Insulation	2,162	2.8%	16%	$0.63
Steam Trap Maintenance	1,689	2.2%	13%	$0.45
Boiler Load Control	1,081	1.4%	8%	$0.13
Other Boiler Measures	2,698	3.5%	20%	$0.20
HVAC Measures	356	0.5%	3%	$4.47
Efficient Process Heat Burners	1,738	2.3%	13%	$1.85
Process Controls & Management	1,491	1.9%	11%	$0.51
Other Process Heat	1,984	2.6%	15%	$3.88
Total	**13,198**	**17.2%**	**100%**	**$1.22**

This analysis found economic savings from these cross-cutting measures of 13,198 billion Btu, or 17% of industrial natural gas use in 2025 at a levelized cost of about $1.22 per million Btu saved. Once again, this analysis did not consider process-specific efficiency measures that would be applied at the individual site level. As with electricity, we would anticipate an additional economic savings of 5–10%, primarily at large energy-intensive manufacturing facilities. The overall economic industrial efficiency resource opportunity is on the order of 22–27%. Therefore, the total economic potential for natural gas savings in the industrial sector in 2025 would be about 18,819 Btu.

Chapter Four: Energy Efficiency Policy Analysis

In this section we present the suite of eleven energy policies and five enabling policies that we suggest Arkansas implement in order to enhance energy efficiency in the state. We then estimate the resulting energy savings, costs, and consumer energy bill savings ($) that can be realized from their implementation, though costs and benefits are quantified for only ten of the policies (nine for natural gas). Each policy is analyzed within a three scenario framework: our base case or modified reference case scenario only reflects savings from federal appliance standards; our medium case scenario reflects a significant commitment to efficiency and is the scenario on which we focus the publication of our results; and our high case scenario represents a more aggressive approach where the state takes greater advantage of its available, cost-effective resource potential. Both scenarios recognize the uncertainty associated with long-term planning horizons by making modest assumptions about participation rates and the time required to ramp-up to these levels given Arkansas' unique characteristics. In light of these assumptions, the potential savings we estimate from the policies and programs in both scenarios should be considered conservative. Furthermore, assumptions of participation rates are based off of programmatic experience from other states and do not directly reflect the details from our cost-effective resource assessment above.

The three scenarios are shown in the matrix below (see Table 4-1) for both the policies analyzed quantitatively and the enabling policies. Following the policy discussions we estimate the resulting energy savings, costs, and consumer energy bill savings ($) that can be realized from their implementation. In the discussion of our EERS policy, we briefly examine the sorts of programs that utilities can implement in order to satisfy the remaining savings obligation as stipulated by the EERS.

Table 4-1. Matrix of Energy Efficiency Policies in Modified, Medium, and High Case Scenarios

Electricity		Scenario One: Modified Reference Case	Scenario Two: Medium Case	Scenario Three: High Case
1	Energy Efficiency Resource Standard (EERS)	None	14.25% electric savings by 2025 relative to 2009 sales; 10% gas savings by 2025 relative to 2009 sales.	18% electric savings by 2025 relative to 2009 sales; 12% gas savings by 2025 relative to 2009 sales.
2	Behavioral Initiative*	None	Customer end-use information provided through utility billing statements.	Same as Scenario Two plus feedback mechanisms, e.g., smart meters.
3	Weatherization of Severely Inefficient Homes*	Current Policies	Ramp-up AWP to weatherize 1,600 homes annually by 2012.	Ramp-up AWP to weatherize 2,400 homes annually.
4	Manufactured Homes Initiative*	None	Weatherize/replace 500 manufactured homes annually by 2021.	Weatherize/replace 1,000 manufactured homes annually by 2015.
5	Industrial Initiative*	None	Expanded State Manufacturer Initiatives.	Same as Scenario Two plus additional resources for more annual audits.
6	Research, Development, and Demonstration Initiative*	None	Establishment of a state-supported entity focusing on the development of new technologies and practices to facilitate local development of energy-efficient products.	Same as Scenario Two.
7	Rural & Agricultural Initiative*	None	Develop/continue educational program; leverage USDA-REAP program; train workforce of agricultural energy auditors; and create pool of matching funds for USDA grants.	Same as Scenario Two.
8	Building Energy Codes, Voluntary Programs and Enforcement	Current Track	Increase savings from codes 30% by 2013 and 50% by 2020; enhance code enforcement and compliance.	Increase savings from codes 30% by 2012 and 50% by 2017; enhance code enforcement and compliance.
9	Combined Heat & Power (CHP)	Current Policies	$500 incentives and removal of disincentives toward CHP	$1000 incentives and removal of disincentives toward CHP
10	Lead by Example (Energy Efficiency in State and Local Government Agencies)	Current Policies	Reduce total energy consumption in existing state buildings 20% by 2014, 30% by 2017 (according to HB 1663), and ramp up to 50% savings by 2025; 10% savings in new buildings beyond code.	Same as Scenario Two, instead ramp-up to 65% savings by 2025; 10% savings in new buildings beyond code.
11	Demand Response Programs**	Current Policies	Deployment of smart technologies and smart tariffs.	Same as Scenario Two.
Enabling Policies				
1	Energy Efficiency Clearinghouse	Expand upon AEO's proposed online Industry Clearinghouse to include all sectors.	Enabling Policy	Enabling Policy

2	Evaluation, Measurement, and Verification	Improve utility annual energy efficiency program evaluation reports.	Enabling Policy	Enabling Policy
3	Financing	Investigate third-party sources of capital to provide financing to end-use customers for energy efficiency improvements.	Enabling Policy	Enabling Policy
4	Lost-Revenue Recovery/Incentives	Continue decoupling for gas utilities; implement decoupling or short-term revenue recovery for electric utilities; incentives for robust goals.	Enabling Policy	Enabling Policy
5	Public Outreach	Continue to fund Energy Efficiency Arkansas to increase awareness.	Enabling Policy	Enabling Policy
6	Workforce Development Initiative	Continue to fund Energy Efficiency Arkansas' training resources; establish interagency stakeholder group to coordinate workforce development activities.	Enabling Policy	Enabling Policy

*Savings from these policies count towards the utility savings targets mandated by the EERS.
**The assessment of demand response potential is covered in the next section and in Appendix D.

Discussion of Policies Analyzed

Energy Efficiency Resource Standard

An Energy Efficiency Resource Standard (EERS) is a quantitative, long-term energy-saving target for utilities that is met by implementing energy efficiency programs in order to help customers save energy in their homes and businesses. While the PSC could set targets annually as a part of the ratemaking process, an EERS locks in future savings and creates certainty, making it easier for utilities to shape their resource plans. Typically investor-owned utilities are required to meet this target, though electric cooperatives and municipal utilities are occasionally included and sometimes given the choice to opt in (see Table 4-2). Most commonly, utilities are charged with meeting the targets, but in some cases, states appoint a state agency or non-utility third-party administrator to implement programs. Currently twenty-seven states (including Arkansas) have enacted mandatory energy savings goals through legislation or regulatory order and another three have an EERS pending.[11] The EERS approach contrasts with many earlier state-legislated efficiency targets that were set in terms of funding levels rather than energy savings levels. Other models that did set energy-saving targets were short term, setting them one year at a time, whereas EERS targets require multi-year, long-term targets. EERS targets are typically set independently of specific program, technology, or market targets in order to give utilities maximum flexibility to find the least-cost path toward meeting the targets (Nadel 2007; ACEEE 2008).

Table 4-2. State EERS Applicability to Municipally-Owned and Cooperative Utilities

State	Notes
Arizona	IOUs and cooperatives (Docket No. RE-00000C-09-427, Decision No. 71436)
Connecticut	Municipal utilities, IOUs, and retail suppliers required to comply with RPS, which includes efficiency
Delaware	Electric distribution companies, cooperatives, or municipal electrics serving state residents (SB 106, Sec. 1501(a))
Hawaii	Cooperatives (HB 1464, Sec. 3)
Indiana	All jurisdictional utilities. Some municipally-owned utilities have opted out of IURC jurisdiction (DSM Cause 42693)
Iowa	Municipal and cooperative utilities required to implement programs and set savings goals (2009 Iowa Code, Title XI, Subtitle 5, Chapter 476.1A-476.1C)
Maryland	Municipals and cooperatives (MD Public Utility Companies Code, Title 7-211)
Mass.	Municipal aggregators (Cape Light Compact) (D.P.U 09-116)
Michigan	All regulated utilities (MCL 460.1021 et seq.)
Minnesota	Municipals and cooperatives (MN Law: Chapter 136-S.F.No. 145)
N. Carolina	Electric coops and municipals can use DSM or efficiency to satisfy 10% renewable standard (N.C. Gen. Stat. 62-133.8 (b)
Ohio	Electric distribution utilities, which includes cooperatives (O.R.C. 4928.66)
Pennsylvania	Electric distribution companies with at least 100,000 customers (Act 129 of 2008)
Texas	All electric and transmission and distribution utilities (PUCT Substantive Rule Sec. 25.181)

There are many examples of program designs that have proven successful over the past three decades, across states with varying demographics and demand requirements. In Table 4-3 below we present EERS targets that have been mandated in other states, as well as those that are pending, voluntary, or combined with a renewable energy standard (RES). Detailed information on the state targets identified in this table can be found in Appendix C.

[11] See http://www.aceee.org/topics/eers.

Table 4-3. Utility Targets

State	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Cumulative
Arizona		1.03%	1.02%	1.20%	1.58%	1.56%	1.54%	1.51%	1.49%	1.47%	1.45%	1.43%	**15.28%**
Arkansas		n/a	0.25%	0.50%	0.75%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**1.5%**
California	1.31%	1.26%	1.27%	1.28%	1.41%	0.92%	0.88%	0.90%	0.90%	0.91%	0.90%	0.89%	**12.82%**
Colorado	0.53%	0.76%	0.80%	0.85%	0.90%	0.95%	1.00%	1.05%	1.10%	1.15%	1.20%	1.20%	**11.49%**
Connecticut	1.00%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	**17.50%**
Delaware	0.50%	0.75%	1.25%	2.50%	3.00%	3.00%	4.00%	n/a	n/a	n/a	n/a	n/a	**15.00%**
Hawaii	0.59%	0.60%	0.75%	0.75%	1.00%	1.00%	1.25%	1.25%	1.50%	1.50%	1.75%	1.75%	**13.69%**
Illinois	0.40%	0.60%	0.80%	1.00%	1.40%	1.80%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	**18.00%**
Indiana		0.30%	0.50%	0.70%	0.89%	1.09%	1.29%	1.49%	1.69%	1.89%	1.99%	1.99%	**13.81%**
Iowa	1.00%	1.20%	1.30%	1.40%	1.40%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**6.30%**
Maryland	0.99%	1.23%	1.71%	2.19%	2.65%	2.64%	3.09%	n/a	n/a	n/a	n/a	n/a	**14.51%**
Massachusetts	1.00%	1.50%	2.00%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	**26.10%**
Michigan	0.30%	0.50%	0.75%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	**10.55%**
Minnesota		1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	**16.50%**
Nevada*	0.77%	0.03%	0.78%	0.04%	0.79%	0.05%	0.55%	0.05%	0.05%	0.05%	0.05%	0.55%	**3.76%**
New Mexico		0.86%	0.85%	0.84%	0.83%	0.82%	0.60%	0.59%	0.59%	0.58%	0.76%	0.75%	**8.06%**
New York	2.10%	2.12%	2.16%	2.18%	2.20%	2.23%	2.26%	n/a	n/a	n/a	n/a	n/a	**15.25%**
North Carolina*		0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.38%	0.38%	0.21%	0.21%	**2.92%**
Ohio	0.30%	0.50%	0.70%	0.80%	0.89%	0.99%	0.99%	0.99%	0.99%	0.99%	1.99%	1.99%	**12.13%**
Pennsylvania			1.00%	0.99%	0.99%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**2.98%**
Rhode Island	1.16%	1.15%	1.14%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**3.44%**
Texas	0.34%	0.34%	0.34%	0.34%	0.34%	0.34%	0.34%	0.34%	0.34%	0.34%	0.34%	0.34%	**4.08%**
Utah**		1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	**11.00%**
Vermont	2.61%	2.59%	2.57%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**7.78%**
Virginia***	0.68%	0.67%	0.67%	0.67%	0.66%	0.66%	0.65%	0.65%	0.65%	0.64%	0.64%	0.63%	**7.86%**
Washington	0.74%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	**11.74%**
Wisconsin			0.75%	1.00%	1.25%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	**13.50%**
Notes:	* Combined RES/EERS, only EE shown here ** EERS Pending *** Voluntary Goal												

Indiana's Utility Regulatory Commission set aggressive targets for its utilities through an order approved December 9, 2009, ramping up to 2% by 2019, for a cumulative savings target of around 14% by 2020. Ohio's State Legislature enacted targets requiring a cumulative reduction in energy consumption of at least 22% by 2022. In both cases, these targets start modestly (0.3% of sales in the first full year), ramp up to 1% per year 5 years later, and reach 2% per year 5 years after that. Notably, Arkansas shares a major utility (AEP) with these two states.

Modeling a Successful EERS in Arkansas

ACEEE generally recommends that EERS targets start at modest levels, around 0.3% of annual sales, and ramp up over several years to savings levels currently achieved by the most successful states, or around 1.25–2.0% of annual sales. However, through our discussions with stakeholders in Arkansas as well as our review of EAI's and SWEPCO's efficiency potential studies, it became clear that Arkansas does not yet have the foundation or experience to ramp up to levels attained by the most successful states, and it may well take five years or more for Arkansas to reach such levels.

Additionally, we recommend that six of the policies be allowed to count towards the EERS targets, those being the Behavioral Initiative, Weatherization of Severely Inefficient Homes, the Manufactured Homes Initiative, the Industrial Initiative (including savings from those companies choosing to self-direct, discussed below), the RD&D Initiative, and the Rural and Agricultural Initiative. We allow savings from these programs to count towards the EERS targets because they will most likely be funded from utility rates, so utilities should receive credit for the savings. The remaining portion of the targets will be met by other utility programs, such as those offered during the Quick Start phase (industrial lighting, public education, etc.) and those that will be offered during the "comprehensive" phase.

Arkansas' cooperative utilities were not included in the EERS targets because they have been investing in energy efficiency for decades and the PSC has not required them to participate in the utility-funded efficiency programs under the premise that the coops are achieving equivalent savings on their own. However, if the IOUs are to ramp up their energy efficiency efforts, the cooperatives will also need to increase their efforts so they can continue to make the case that they are achieving similar savings on their own. In our enabling policy discussion below on evaluation, measurement and verification, we note that it is important that cooperatives should only be allowed to remain independent if they can prove they are meeting target levels roughly similar to those required by the IOUs. Therefore, in our medium case, we assume that Arkansas' cooperatives ramp up their own programs so that they reach half the savings as a percent of sales that the IOUs are meeting; in our high case, we assume that the cooperatives are able to reach the same savings targets as the IOUs.

In order to facilitate compliance with an EERS without jeopardizing the bottom line of participants, a few conditions should be considered prior to its implementation. First is the inclusion of a "self-direct" option for large industrial customers in the state. Several of our stakeholders acknowledged that many of Arkansas' industrial firms have been incorporating energy efficiency practices into their operations for years, though they still have significant potential yet to be captured. The self-direct option would allow large industrial customers to continue to direct their own efficiency investments, as long as they demonstrate that they are achieving the same savings targets, as a percent of consumption, as the utility percent savings targets. Savings from industrial customers directing their own efficiency programs should also be allowed to count towards the utility targets. Large industrial customers who self-direct would not have to pay for most of the utility programs, nor can they participate in these programs. Such a program is being implemented in Michigan, based on detailed negotiations among interested parties in that state and codified in Sec. 93 of PA295 of 2008. Over time, the Arkansas PSC could consider whether the large industrial targets should diverge from the utility targets, if savings opportunities are fully captured.

Second, an EERS should consider the disparity in energy demand across utilities. Small utilities generally have more limited staffing and capabilities and may need lower targets or more time to reach a specific target level. Also, we know some small utilities are concerned that targets will be particularly challenging if economic development objectives are achieved and a large energy consumer moves into their service territory adding load to the system. To address this, the EERS targets should be set so that they are relative to what demand would have been without energy efficiency programs. In other words, if demand is at 100 units and a new customer increases total load to 110 units, a 1% savings target would require a reduction in load of 1 unit, or 1% of the previous load, so that total load would be reduced to 109. Similarly, utilities should not be given credit for naturally occurring decreases in sales: utilities must demonstrate sales reductions are a result of their efficiency programs.

Several stakeholders opined that the targets should be tailored to the individual utility, noting the significant differences in demographics, socioeconomic conditions, and other variables across utility service territories: the reason ACEEE is not recommending this is that we believe that the targets we set are modest targets and can be met by all Arkansas utilities. Additionally, in ACEEE's experience in other states, these variations purported by utilities are often overstated. Nonetheless, if Arkansas eventually pursues more aggressive investments in energy efficiency or if demand for energy within a utility service territory increases dramatically, especially in a short period of time, the PSC should reserve the right to vary the targets if needed and appropriate.

For Arkansas, the PSC has recently opened a docket that, among other items, is to consider setting savings targets (Docket No. 10-010-U). This is the most likely route to an EERS in Arkansas. Another option would be to enact legislation. To facilitate the development of a statewide EERS in Arkansas, ACEEE has recently created guidance language for creating an EERS, illustrating basic provisions that should be considered for inclusion in a state-level EERS, with accompanying explanations for each provision. This example is intended to provide state legislators, regulators, and other stakeholders with a starting point in drafting a state-specific EERS and as an initial framework from which the negotiation process may advance, taking into consideration the regulatory environment of the individual state. ACEEE's guidance language is available on ACEEE's Web site.[12]

Electricity

In our medium case scenario, we recommend establishing annual targets that accumulate to about 14.25% savings by 2025, with incremental annual savings a function of prior year sales. For Arkansas cooperatives, we assume they would be achieving savings through their own programs equivalent to annual targets accumulating to about 7% of sales. For the IOUs, this is a fairly modest target considering that the majority of states with an EERS are aiming to achieve 10–15% savings by 2020. We assume that annual targets are set to begin at 0.25% in 2010 and ramp up to 0.5% in 2011, 0.75% in 2012 and 2013, and leveling off at 1.0% annual savings in 2015 for the remainder of the analysis period. Under these assumptions, EERS savings accumulate to 5,400 GWh, which is equivalent to about 10% of sales in 2025. Savings from cooperatives contribute an additional 960 GWh, or 2% of sales in 2025, for a total of over 6,300 GWh, or about 12%.

In our high case scenario, we recommend establishing annual targets that accumulate to 18% savings by 2025, with incremental annual savings a function of prior year sales. For Arkansas' cooperatives, we assume they would be achieving the same annual targets through their own programs. We assume that annual targets are set to begin at 0.25% in 2010 and then ramp up to 0.5% in 2011, 0.75% in 2012 and 2013, 1.0% in 2014 and 2015, 1.25% in 2016–2020, and 1.5% annual savings for the final five years of the analysis period. Under these assumptions, EERS savings accumulate to about 9,300 GWh, which is equivalent to almost 17% of sales in 2025.

In 2009, Arkansas' electric utilities achieved annual savings equal to 0.13% of sales, which is about halfway towards the first-year annual target we recommended in our EERS analysis (see

[12] See http://www.aceee.org/sector/state-policy/toolkit. Given that the energy industry is becoming increasingly more dynamic, this document will continue to change and will consistently be a "work in progress," attempting to capture the most recent developments in energy efficiency resources standards.

Table 4-3 above). Utilities had set savings goals for 2009 that collectively reached about 0.08% relative to 2009 sales, so achieved savings actually surpassed targets by two-thirds, or 67%. According to the annual energy efficiency reports filed in 2009, the electric utilities have set savings goals in 2010 to collectively achieve 0.08% relative to 2010 sales as estimated in ACEEE's reference case but have obligated an additional 50% to the total utility program budget relative to their 2009 budgets. With investments in consumer education begetting greater program participation, more aggressive goals and deeper budgets should help the electric utilities to exceed 2009's savings of 0.13%.

Natural Gas

In addition to savings targets for distribution utilities, several states have set targets for natural gas distribution companies. Leading natural gas efficiency programs in the nation are achieving 0.5% to 1% incremental annual natural gas savings per year after several years of running programs. Two of the three natural gas utilities in Arkansas, however, are facing declining customers in the residential sector and slow growth overall, which could impact their ability to meet aggressive mandated targets. On the other hand, promoting efficiency and reducing customer bills are likely to be important for customer retention in the long term. Nevertheless, customer decline ranges only 5–7% over the last decade and in one case, declining sales trends appear to be cyclical and fluctuate as a function of prices rather than reflecting a shifting trend towards electric sources of heat. Ultimately, slight variations in sales, either upwards or downwards, will only affect the absolute savings as opposed to the percent savings.

As such, in our medium case scenario we have modeled an EERS that is relatively less stringent in the early years, e.g., 0.2% in 2010, 0.3% in 2011, etc., ramping up to annual targets of 0.8% in 2016 and thereafter so that, in 2025, the cumulative energy savings reaches about 10%. Under these assumptions, EERS savings accumulate to 17,400 BBtu, which is equivalent to almost 11% of sales in 2025.

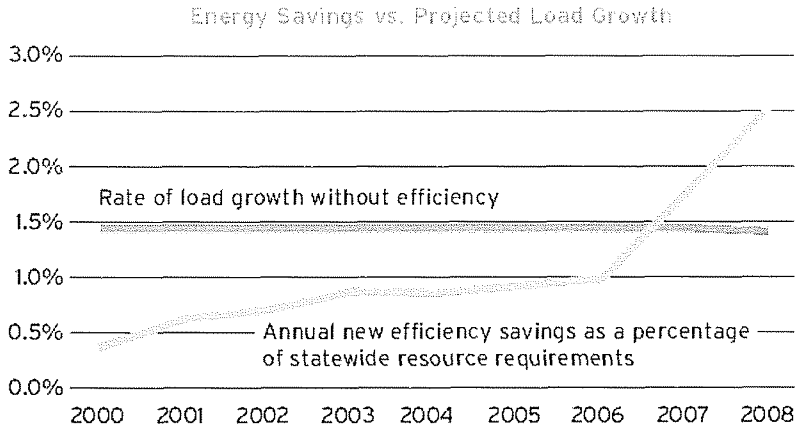
In our high case scenario, we increase the annual targets to 0.9% in 2017 and 1.0% in 2018 and thereafter, for cumulative savings of about 12%. Under these assumptions, EERS savings accumulate to over 20,000 BBtu, which is equivalent to about 12% of sales in 2025.

In 2009, Arkansas' natural gas utilities achieved only 0.005% savings as a percent of sales in that year through the four energy efficiency programs that they offer. While the natural gas utilities cite declining consumers as a major impediment to generating savings through efficiency, more aggressive investments in programs that yield tangible benefits have the potential to increase overall savings considerably. For example, in 2009 Arkansas' natural gas utilities spent only 70% of their budgets for energy efficiency programs. Of the total amount spent, the greatest allocation (40%) was for the utility co-funded Energy Efficiency Arkansas, a consumer education/training program, for which energy savings are virtually impossible to quantify, but an extremely vital program nonetheless, especially in a state with relatively little experience with energy efficiency (Docket #s 08-057-RP, 08-058-RP, and 08-059-RP). However, each natural gas utility funds its own efficiency education program in addition to EEA. The only two programs offered by the natural gas utilities that are able to generate savings are the utility co-funded AWP and the Commercial-Industrial Natural Gas Energy Audit Program (CNGEAP). Added funding and effort to increase participation in the AWP and CNGEAP programs would help these utilities achieve substantially greater savings.

EERS Profile: Vermont

The state of Vermont provides an interesting case study that can illuminate what may be possible in Arkansas. Like Arkansas, Vermont is a predominantly rural state, with a limited number of major cities (although the cities in Arkansas are considerably larger than those in Vermont). Vermont began significant efficiency programs in 2000 and has gradually ramped them up, with a major expansion taking place in 2007 and 2008. In the first year, as shown in Figure 4-1, electricity savings achieved were about 0.4% of sales. Annual savings gradually rose to 1% of sales in 2006. Through 2006, the program had a limited budget that could not fund additional savings. In 2007, after a decision by the Vermont Public Service Board that much more savings were possible and cost-effective, energy efficiency budgets and savings increased substantially, hitting about 1.8% of electric sales in 2007 and 2.5% in 2008. In 2009, savings were 1.8%. Although historically Efficiency Vermont targeted lighting as a major source of energy savings, they have significantly expanded their programs to target other efficient product categories, such as refrigeration, water conservation devices, and programmable thermostats. In 2009, savings from lighting were 60% lower than in 2008.

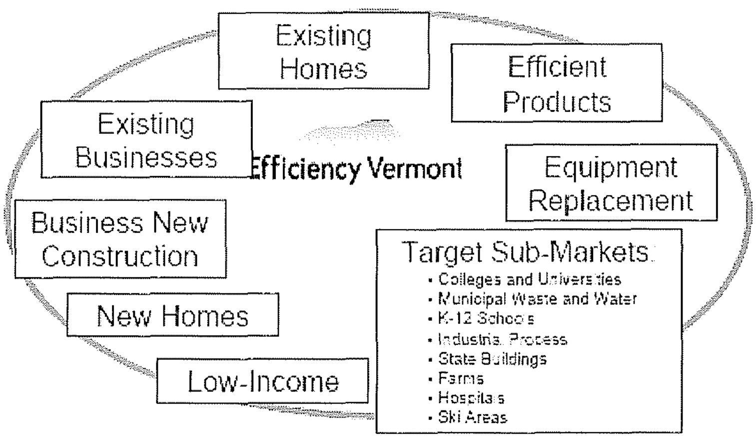
Figure 4-1. Efficiency Savings in Vermont



Source: Efficiency Vermont and Vermont Public Service Board

To achieve these objectives, Vermont runs a comprehensive suite of programs. These are illustrated in Figure 4-2.

Figure 4-2. Efficiency Vermont Markets and Programs



On a cumulative basis, since measures installed in the early years are generally still in place, measures installed over the 2000–2008 period reduced electricity sales by about 9% in 2008 relative to what they would have been if no energy efficiency programs were offered. The programs offered have had an average levelized cost of about 2.7 cents/kWh to the program administrator (including incentives, administration, and evaluation costs); the cost per kWh on a Total Resource Cost basis (counting customer costs for efficiency investments) was not reported.

Program Models

There are numerous best practice models for energy efficiency programs from around the nation. In the text box below, we present several of these program types along with specific examples of successful implementations that are drawn from ACEEE's report *Compendium of Champions: Chronicling Exemplary Energy Efficiency Programs from across the U.S.* (York, Kushler, and Witte 2008). Arkansas' utilities have already begun to run some of these energy efficiency program models through their Quick Start programs, however they are far from achieving the levels of savings outlined in this EERS policy analysis. As utilities and the PSC move forward in developing and implementing their "comprehensive" energy efficiency programs, the examples highlighted in ACEEE's *Best Practices* report and the text box below (Table 4-4) will provide some guidance on how to expand upon the existing programs in order to offer well-run, comprehensive, and cost-effective utility energy efficiency programs over the long term.

Table 4-4. Examples of Proven Residential and Commercial Efficiency Programs: The National Action Plan's Rapid Deployment Energy Efficiency Toolkit

As described in: *http://www.epa.gov/RDEE/documents/rdee_toolkit.pdf*, ***except Wisconsin Focus on Energy and Northwest Industrial Efficiency Alliance***

ENERGY STAR Labeled Products: This residential and small commercial sector program promotes efficient lighting (CFLs and fixtures) and appliances through a variety of incentive structures including direct rebates to the customer as well as upstream incentives. This program generally targets the broad residential and small commercial marketplace. Particular products may be selected for inclusion, such as lighting products or home appliances. Savings will depend upon the products included. Typical savings range from approximately 0.5 to 3.0 MBtu per participant.

Residential Energy Audit and Direct Installation: This program targets the same market and works with the same set of contractors as Home Performance with ENERGY STAR (see below); the key difference is a more basic audit and a less-extensive and lower-cost set of measures, such as CFLs, hot water heater wraps, pipe insulation, and low flow showerheads. Typical savings are approximately 3 to 6 MBtu per participant.

Home Performance with ENERGY STAR: This residential sector program offers whole home retrofits using qualified contractors, established home assessment protocols, and incentives from the program sponsor. This program can be a good strategy particularly for older, pre-code constructed homes. The program is estimated to reduce home energy bills by 20% on average.

Residential Efficient HVAC: This program targets HVAC contractors and homeowners to increase sales and proper installation of ENERGY STAR-qualified HVAC equipment, such as air conditioners and furnaces.[13] Savings are very sensitive to local climate conditions, but the minimum savings range per participant is approximately 5 to 20 MBtu.

Non-Residential Prescriptive Rebates: This program provides incentives to the commercial, institutional, and industrial market for upgrade or retrofit of equipment with new, more energy-efficient equipment, such as lighting, HVAC equipment, and products like motors and refrigerators. Particular equipment and products may be selected for inclusion in this program, such as lighting; savings depend upon the equipment and products included. Generally, a large percentage of program savings come from lighting retrofits.

Non-Residential Retrocommissioning: Retrocommissioning offers building owners a systematic process for evaluating a structure's major energy-consuming systems and identifying opportunities to optimize equipment operation. Retrocommissioning tunes-up existing buildings, improving their energy efficiency and operational procedures. It is typically carried out through local networks of commissioning providers. Typical savings range from approximately 4,000 to 20,000 MBtu per participant.

Commercial Food Service Equipment Incentives: This program rebates energy-efficient commercial food service equipment such as refrigerators, freezers, steamers, fryers, hot food holding cabinets, ice machines, dishwashers, ovens, and other technologies, primarily aiming to influence the buyer to purchase more efficient equipment when their existing equipment has failed. Typical savings range from approximately 20 to 60 MBtu per participant.

[13] See: http://www.aceee.org/node/174/all

Continued....

Non-Residential Custom Incentives: A commercial and industrial Custom Program supports C&I customers in identifying and implementing site-specific and complex energy efficiency opportunities, which often require calculations to determine energy savings. A typical project may involve industrial process efficiency, chillers/boilers, data center efficiency, or electric motor retrofits, or projects that otherwise fall outside of the prescriptive program. Savings per project can be very large, but vary widely by state/industry.

Non-Residential Benchmarking and Performance Improvements: This program works with commercial facility operations staff and owners to benchmark, monitor, and improve building energy performance using tools such as ENERGY STAR Portfolio Manager and building sub-metering equipment, as well as to recommend energy efficiency upgrades based on analyses of building performance data. This program is estimated to reduce building energy use by 10 to over 30%.

Non-Residential On-Site Energy Manager: This program assists larger customers by providing an On-Site Energy Manager (OEM) to work with them for a six-month period or longer. During their tenure with a business, the OEM will evaluate facilities' energy use and work with maintenance staff to reduce energy usage and costs. Long-term energy and cost savings of 10-15% are achievable, largely through behavioral changes.

Wisconsin Focus on Energy Industrial Program: This nonprofit organization has a program specifically for industrial efficiency generally focused on projects greater than one-year payback through both prescriptive and custom offerings that complement each other. Focus on Energy programs are both technology- and market sector-based, working with sector trade allies. The program offers field-based technical support, including third-party review of vendor proposals, onsite energy management, technology assessments, measurement and verification, information and education, and project application support.

Northwest Industrial Efficiency Alliance: The Northwest Energy Efficiency Alliance (NEEA) operates an industrial program that leverages industrial allies such as the Northwest Food Processors Association. The effort supports industrial co-led efforts that leverage DOE's Save Energy Now tools and resources to provide corporate executives with an understanding of the strategic importance of efficiency; the resources to identify and implement energy efficiency; and support for the identification of suppliers and technologies to fulfill industry's strategic energy management needs.

Behavioral Initiative

Traditionally, state governments and utilities have approached the advancement of energy efficiency predominantly through mandates, such as building energy codes, and financial incentives, like rebates on energy-saving appliances. But creating laws is a lot less complicated and costly than enforcing them, and financial incentives do not always reduce the incremental cost of efficiency upgrades enough to persuade households to invest in them. Therefore, to complement mandates and incentives, an initiative to encourage consumers to modify their energy use habits would be useful. Guided by research into social psychology from the past several decades, utilities and the energy industry in general have grown to realize the power of disseminating localized, comparative information on household energy consumption to customers in order to influence their behavior. This comparative information, in the form of periodic reports, is equivalent to having an in-home energy monitor that provides information such as seasonal variations of energy use, but goes a step further by comparing one household's consumption patterns to similar households. The effect being that, when households are given information on how their peers are performing relative to themselves, there is a profound inclination to follow suit. Robert Cialdini, a social psychologist, regards this as "social proof," or a primitive survival instinct akin to peer pressure (Tsui 2009).

OPOWER (previously known as Positive Energy) has taken advantage of this intrinsic social characteristic and turned it into a business model. They have shown that mailing utility customers periodic reports on their household electricity consumption and comparing that usage to other customers with similar demographics and housing characteristics not just in the same city, but in the same neighborhood, can reduce household consumption between 1.5% and 3.5%. So far, savings have been demonstrated over a period of a few years; additional information on longer-term persistence will become available in coming months and years. The personalized reports the company generates consist of monthly electricity consumption that compares one's usage patterns to similar neighbors as well as to those neighbors that are relatively more successful (or unsuccessful) in implementing energy efficiency in their home. Based on individual household consumption patterns, the reports also make efficiency recommendations—ranging from simple steps like turning down your thermostat to more time- or dollar-intensive steps like purchasing ENERGY STAR products—that quantify the potential savings, both in kilowatt and dollar terms. Rebate coupons targeting a household's more energy-intensive end-uses are simultaneously issued with the reports, increasing the probability that consumers will respond to the efficiency recommendations.

Other companies are also developing products to compete with OPOWER, such as Google's Power Meter (see http://www.google.com/powermeter/about/about.html) and Grid Point (http://www.gridpoint.com/Home.aspx). There are also opportunities to provide even more information to consumers via the Web or in-home monitors and achieve even higher savings.

Our behavioral initiative is modeled off of OPOWER's program illustrated above, though we acknowledge that other private sector companies, such as Google, are developing similar online resources to encourage behavioral change. One caveat to this policy must be understood by the reader. As this policy is intended primarily to impact consumer behavior, we assume that the only costs incurred are for program and administrative purposes, such as marketing and the issuing of reports. Any investment costs, such as purchasing efficient equipment or incentives provided by utilities, are borne by consumers or by utilities through their efficiency programs. We also assume a one-year persistence rate, i.e., that savings realized in one year are not perpetually generated and therefore do not accumulate.

Additionally, we assume that there are two sets of participants in the program. The first set is the total number of participants, all of whom receive monthly reports that allow them to ramp up to 2% annual savings. The second set is a subset of the total number of participants, where the installation of in-home displays in addition to the monthly reports allows this subset of participants to achieve an additional 6% savings, for a total of 8% annual savings.

In our medium case scenario, we assume that 80% of households in Arkansas participate in the program. These households are able to ramp up to the minimum 2% annual savings over four years, or by 2013, which is sustained for the remainder of the analysis. We then assume that our subset of participants with in-home displays, or 20% of the total number of participants (20% of 80%), is able to ramp up to 6% savings over ten years, or by 2019, which is also sustained for the remainder of the analysis.

Our high case builds upon the assumptions made in our medium case scenario. However, in this scenario we assume that 90% of Arkansas households participate in the program and are able to ramp up to 2% annual savings over two years, or by 2012, which is sustained for the remainder of the analysis. We assume our subset of participants with in-home displays, or 30% of the total number of participants in this scenario (30% of 90%), is able to ramp up to 6% savings over five years, or by 2014, which is also sustained for the remainder of the analysis.

Building Energy Codes, Voluntary Programs and Enforcement

Building energy codes are a foundational statewide policy to ensure that efficiency is integrated into all new buildings in Arkansas. If efficiency is not incorporated at the time of construction, the new building stock represents a "lost opportunity" for energy savings because efficiency is difficult and expensive to install after construction is completed. Mandatory building energy codes are one way to target energy efficiency by requiring a minimum level of energy efficiency for all new residential and commercial buildings. Although enforcing compliance with energy codes can be difficult and costly, compliance is facilitated by introducing codes that are not convoluted in the sense that they allow contractors to follow either performance-based or various prescriptive-based paths.

The Arkansas Energy Code

The Arkansas Energy Code was last updated October 1, 2004, to follow the 2003 International Energy Conservation Code (IECC) for both the residential and commercial sectors, the latter referencing ASHRAE 90.1-2001. Arkansas is expected to add another 6,600 homes in 2010, or another 0.6% to its existing housing stock of 1.3 million homes, down from 1% in 2008 and 0.8% in 2009. This decline is expected to continue, albeit slightly, into 2011 and 2012, rebounding close to 1% annual growth by 2014 and averaging 0.75% through 2025 (Economy.com 2010). Based on employment forecasts, which show annual employment growth increasing through 2013 and flattening out thereafter, we estimate commercial construction to grow an average of 2% per year between 2010 and 2025 (Economy.com 2010).

Arkansas' building codes are equally or more stringent than the majority of the other states in the South Central Census Region. However, there is no set schedule to update the state energy codes. Adopting new energy codes in Arkansas is an inherently political process and as such is slow to transpire. Proposed changes to the codes are initiated by the Arkansas Energy Office and reviewed by interested parties, with the agreed changes submitted for public hearing. Following approval at the public hearing, the proposed changes must pass through the AEO and two legislative committees prior to their adoption in the next iteration of the code.

Augmenting the Efficacy of the Arkansas Energy Code

While there is no set schedule for updating the Arkansas Energy Code, Governor Mike Beebe has made a commitment to making all newly-constructed state-owned buildings more energy efficient through his signing of House Bill 1663 in April 2009 and codified as Act 1494. The law was introduced to promote the conservation of energy and natural resources in buildings owned by the state or institutions of higher education. It establishes performance criteria and goals for new and major-renovated public facilities, requiring these facilities to reduce baseline energy consumption by 10% as determined in accordance with the performance rating method of Appendix G of the American Society of Heating, Refrigeration, and Air-Conditioning Engineers (ASHRAE) standard 90.1-2007.

Compliance and enforcement are critical in achieving the full savings potential from new building energy codes. Our interviews with stakeholders revealed a serious lack of compliance permeating the state, especially in non-urban areas. In order to enforce compliance, Arkansas is working on addressing this issue, leveraging funding from the SEP to support its efforts for builder and code enforcement training. In fact, enhancing code compliance has been identified by the AEO as critical issue that must be focused on prior to adopting future energy codes. And to ensure that contractors are consistently given the most up-to-date training, the AEO is considering requiring builders to obtain continuing education credits, so they can maintain knowledge of code requirements as they are changed or enhanced. The need for incorporating energy efficiency training into the General Contractor Licensing process was brought up by several of our stakeholders, so the AEO should strongly consider these continuing education credits as well as other training opportunities in general for contractors. There is also a need for greater compliance surveys of new buildings, though a funding source for regular reports is needed to support this effort. Also, dedicated energy code experts should be hired to assist code inspectors in the areas of highest growth, such as greater Little Rock and the northwest portion of the state.

In our medium case scenario, we assume that the 2010 IECC is adopted in 2012 and becomes effective in 2013, reducing energy consumption by 30% in new residential construction relative to the 2003 IECC, the basis for the Arkansas Energy Code (DOE 2009a; EECC 2008, 2009).[14] We then assume that the state energy code is updated in 2018 to achieve 50% savings beyond code (20% above the 2012 IECC),

[14] Savings assumptions for the residential and commercial sectors are based on individual state code analyses conducted by the U.S. DOE and supplemental ICF analyses at the national level.

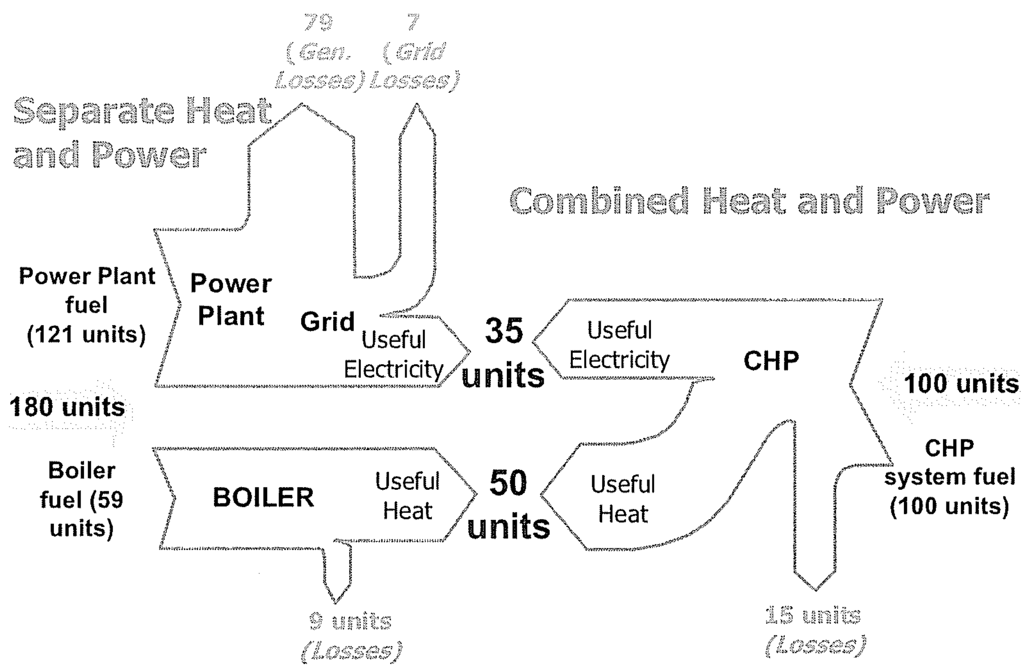
which would become effective in 2020. For the commercial sector, we assume that the Arkansas Energy Code is updated to reference ASHRAE 90.1-2010 in 2012, effective 2013. The U.S. DOE estimates that, in Arkansas, ASHRAE 90.1-2007 will generate an average nonresidential savings of around 4% across the state relative to the 2003 IECC (DOE 2009b). Additionally, the 2010 version of the ASHRAE 90.1 is expected to save 30% beyond ASHRAE 90.1-2007, though capturing the full 30% savings is unlikely for most regions in the country. For this analysis we assume that these two impacts cancel each other out so that Arkansas can capture 30% savings by upgrading from the 2003 IECC to ASHRAE 90.1-2010, adopting the latter in 2012 and effective 2013. As in the residential sector, we then assume that Arkansas adopts codes in 2018 that achieve 50% savings beyond the 2003 IECC (20% above ASHRAE 90.1-2010), effective 2020. We assume that code official training, compliance surveys, and other efforts enable enforcement levels to start at 50% at the time of adoption of a new code, ramp up to 65% in the second year, and 80% in the third year and later.

In our high case scenario, we assume the adoption of the 2010 IECC in 2012, effective 2013. However, we build upon the medium case scenario to assume that the Arkansas Energy Code is updated in 2017 to achieve 50% savings above the 2003 IECC. We again assume that code official training, compliance surveys, and other efforts enable enforcement levels to start at 50% at the time of adoption of a new code, ramp up to 65% in the second year, and 80% in the third year and later.

Combined Heat and Power

Combined heat and power improves efficiency by combining usable thermal energy (e.g., chilled water and steam) and power production (e.g., electricity). This co-generation process bypasses most of the thermal losses inherent in traditional thermal electricity generation, where half to two-thirds of fuel input is rejected as waste heat. By combining heat and power into a single process, CHP systems can produce fuel utilization efficiencies of 65% or greater (Elliott and Spurr 1999).

Figure 4-3. Schematic Comparing a Combined Heat and Power System to Separate heat and Power Systems



For this report, Energy and Environmental Analysis (EEA), a division of ICF International, undertook an assessment of the cost-effective potential for CHP in Arkansas by assessing the electricity end-uses at existing industrial, commercial, and institutional sites across the state and also considering sites that will likely be built in the future. These facilities would replace a thermal system (usually a boiler) with a CHP system that also produces power and that is primarily intended to replace purchased power that would otherwise be required at the site. EEA identified 497 MW from 16 CHP plants currently in operation. Detailed information from this analysis is provided in Appendix E.

An additional application of CHP considered by this analysis is in the production of power and cooling through the use of thermally activated technologies such as absorption refrigeration. This application has the benefit of producing electricity to satisfy onsite power requirements and displacing electrically generated cooling, which reduces demand for electricity from the grid, particularly during periods of peak demand (see Elliott and Spurr 1999).

Three levels of potential for CHP were assessed:

- Technical Potential: represents the total capacity potential from existing and new facilities that are likely to have the appropriate physical electric and thermal load characteristics that would support a CHP system with high levels of thermal utilization during business operating hours.

- Economic Potential: reflects the share of the technical potential capacity (and associated number of customers) that would consider the CHP investment economically acceptable according to a procedure that is described in more detail in Appendix E.

- Cumulative Market Penetration: represents an estimate of CHP capacity that will actually enter the market between 2008 and 2025. This value discounts the economic potential to reflect non-economic screening factors and the rate that CHP is likely to actually enter the market. This potential is described in the energy efficiency policy scenarios, which are shown in the next section of the report.

The analysis identified an economic potential in the base case of around 50 MW of CHP capacity beyond what is already installed, assuming estimated electricity and natural gas price forecasts. In our medium case scenario, where changes to policies and regulations result in an equivalent reduction in project costs of $500 per MW installed, the economic potential increases to around 120 MW. In our high case scenario, where the changes in policies and regulations reduce costs by $1,000 incentive per MW installed, the economic potential increases to around 400 MW. Policies and market incentives provide an important catalyst to increasing the presence of CHP systems. In the next section, we estimate the impact that such an incentive can have on the market penetration of CHP in Arkansas.

CHP in Arkansas

The current policies and regulatory environment in Arkansas do not encourage the development of CHP (Eldridge et al. 2009). For Arkansas to see greater CHP deployment in the future, it is imperative that these policies be improved. An important, primary effect of encouraging investment in CHP is that it bolsters the ability of large- and medium-scale manufacturers in the state to utilize this technology to lower energy costs, thereby greatly increasing their competitiveness in the market. Decreased dependence on centrally generated electricity is also a boon to the reliability and stability of the grid, providing more dependable access to electricity across the state.

Interconnection standard. Arkansas's interconnection standard currently applies only to certain renewable-energy systems, so it does not apply to CHP unless the system is renewably fueled. The standard also applies only to non-residential systems below 300 kW in capacity (DSIRE 2010). Because most CHP systems are far larger, this interconnection standard—even if it explicitly included CHP—would fail to provide a clear path for interconnecting to the grid for most, if not all, viable systems. The EPA CHP Partnership currently categorizes Arkansas as having an unfavorable interconnection standard for CHP.[15]

ACEEE recommends that Arkansas adopt an interconnection standard in line with recommended national guidelines established by EPA. Ideally, an interconnection standard would allow for systems of at least 20 MW in size, and include multiple tiers of interconnection so that smaller systems would benefit from a more expedited interconnection process. Additionally, the current requirement that customers install an external disconnect switch would prove burdensome on CHP developers and owners, especially for smaller systems.

Net metering. Arkansas's net metering rules, established in 2002 and refined in 2007, currently only apply to renewable energy systems below 300 kW for non-residential applications. Therefore, for non-renewably fueled CHP Arkansas utilities are only required to purchase redistributed power at its avoided cost, meaning that for most cases the revenue generated from repurchase by the local utility does not come close to covering the costs the facility incurs from onsite generation. We recommend that this policy be reviewed to make sure that the associated capital costs are accounted for. The current rules do not fairly reflect the environmental, economic, and reliability benefits of non-renewably fired CHP as an inherently energy efficiency technology.

Financial incentives. The Arkansas Energy Office has identified financial constraints as one of the largest barriers to CHP. The state of Arkansas does not currently offer any financial incentives for CHP, and because CHP installations tend to be capital intensive and require large upfront costs, financial hurdles often preclude development. Due to the current economic environment, many facilities the Arkansas Energy Office has contacted have said that they simply do not have the capital at this time for major projects, regardless of energy savings projections. To further encourage CHP deployment, the state may wish to consider a financial incentive or financing program that directly targets CHP.

CHP in an EERS. As noted earlier, Arkansas does not currently have an EERS. Should the state implement one, as is recommended in this report, it is important that CHP be included as an eligible technology.[16] When CHP is included as an eligible technology, and thus an eligible efficiency resource, there is an increased incentive for CHP developers to bring systems to Arkansas. Including CHP in any definition of an EERS is a positive signal for CHP developers, and can help improve the economics of CHP as utilities are incentivized to deploy technologies that count toward the EERS targets.

Output-based emissions regulations. As part of EPA's Clean Air Interstate Rule (CAIR) protocol, Arkansas allocates criteria pollutant allowances to existing units on an output basis. (Eldridge et al. 2009). This regulatory approach is important for CHP deployment, because it calculates a CHP system's regulated emissions based upon the increased efficiency of a CHP system, giving the CHP system credit for the increased efficiency through which it creates energy. EPA recommends that states adopt these output-based emissions regulations, and has developed guidelines for those emissions.[17]

Standby rates. Finally, Arkansas's standby rates that are applicable to CHP systems are on the whole unfavorable to CHP deployment (ACEEE 2009). Southwestern Electric Power Company provides standby service to customers primarily on a high demand basis with a low energy charge. The applied billing demand is based on the maximum 15 minute demand or 70% of the maximum demand from the previous 11 months, whichever is higher. Because these charges are inflated and vastly disproportionate to the decrease in utility sales, this rate is viewed as burdensome to CHP development and thus unfavorable. Entergy provides standby service to customers who contract for a specific amount of capacity. A

[15] See the EPA's CHP partnership Web pages for additional information on suggested interconnection standards: http://www.epa.gov/chp/state-policy/interconnection.html
[16] For guidance on how to include CHP in and EERS see Chittum and Elliott (2009).
[17] See the EPA's CHP Partnership Web pages for information on recommended output-based emissions regulations: http://www.epa.gov/chp/state-policy/output.html.

moderate reservation fee is assessed each month and anything beyond non-reserved energy is billed at the customer's regular rate. Because these charges are much more reasonable but do not necessarily encourage distributed generation, they are viewed as neutral toward CHP. EPA offers useful guidance to states in developing standby rates that are more conducive to CHP development.[18]

All of these policies could be improved by legislative action or regulatory proceedings. Many states in the U.S. have recently changed and improved their CHP-related policies, providing good examples of steps that should be taken at the state level.

Other barriers. In many cases, facilities have considered biomass CHP systems using wood chips or shavings but have been unable to secure a steady fuel supply. If alternative fuel sources, such as dedicated energy crops, were to become readily available, the market for CHP in Arkansas would be significantly improved. Additionally, many facilities and developers are not aware of where they can obtain support for CHP project research and implementation. One such point of support is the DOE's Southeast Clean Energy Application Center, whose express mission is to facilitate the development of CHP in the Southeast.[19]

Lead by Example

State and local government facilities represent unique opportunities for Arkansas to implement and ramp up energy efficiency practices. Focusing on energy efficiency in Arkansas' various state-owned facilities, such as state agencies and public schools and universities, is not only a way to capture significant energy savings, but it is also a powerful marketing tool to encourage local governments and the private sector to follow the state's example.

Governor Mike Beebe has recognized the importance of leading by example, signing House Bill 1663 on April 7, 2009, which is codified as Act 1494, signaling his commitment to increasing the energy efficiency of Arkansas' state-owned facilities. In the bill, the General Assembly notes that "public buildings can be built and renovated using sustainable, energy-efficient methods that save money, reduce negative environmental impacts, improve employee and student performance, and make employees and students more productive."

To meet these qualitative goals, HB 1663 targets energy efficiency in existing, renovated, and newly constructed state-owned facilities. For existing buildings, the AEO is charged with developing an energy program for public agencies that will reduce total energy consumption per gross square foot for all existing state buildings by 20% by 2014 and 30% by 2017, using reported energy consumption for the 2007–2008 fiscal year as the baseline. The bill also requires the development of an energy audit procedure, to the extent that funds are available. For new facilities or those that have major renovations,[20] the completed project must be certified to at least a 10% reduction below baseline energy consumption as determined by the performance rating method of Appendix G of ASHRAE standard 90.1-2007.

Financing Efficiency Projects in State Facilities

In order to fund these efficiency projects, the state legislature leveraged ARRA funding to establish a $12 million revolving loan fund, dubbed the Sustainable Building Design Revolving Loan Fund (RLF), which was granted to the Arkansas Building Authority (ABA) and will be jointly administered with the AEO. This is a laudable start, but it is highly unlikely that $12 million will be close to enough funding to reach the savings goals mandated in the bill. There is a notion amongst our stakeholders that the $12 million RLF is

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[18] See the EPA's CHP Partnership Web page on standby rates for more information: http://www.epa.gov/chp/state-policy/utility_fs.html

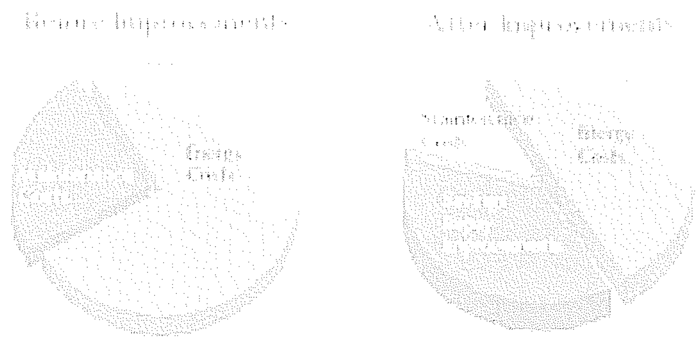
[19] For more information on the Southeast Clean Energy Application Center, visit http://www.chpcenterse.org

[20] "Major renovation" is defined as a building renovation project that: a) costs more than 50% of its current replacement value; b) is larger than 20,000 gross square feet of occupied or conditioned space; and 3) is funded in whole or in part by the state.

only enough funding to cover the energy audits but not any of the retrofitting projects or upgrades for new construction. If Arkansas is going to meet these ambitious savings goals, the legislature will have to look to other sources of financing to supplement the RLF. A state bond issue is currently being considered that would provide $400 million in additional funding for energy-related projects, but state agencies are not allowed to use energy savings from these projects to pay off any bond debt, which would be an ideal way to provide additional funding for efficiency investments by targeting the barriers created by high incremental costs. An amendment to the state constitution in order to change state bonding procedures will be voted on later this year in a referendum.

The most effective mechanism available for financing energy efficiency retrofits in state buildings, which has been utilized extensively in other states, is the contracting of energy service performance contracts (ESPC) through energy service companies (ESCO). The federal government and a number of other states use ESPC's to implement energy efficiency projects at government facilities. Under the ESPC model, state agencies hire pre-qualified ESCO's to implement projects designed to improve the energy efficiency and lower maintenance costs of the facility. The ESCO guarantees the performance of its services, and the energy savings are used to repay this project cost, as shown in Figure 4-4 (KCC 2008; Birr 2008). This model has proven highly effective in many places both in terms of delivering energy savings and in terms of cost-effectiveness (Hopper, Goldman, and McWilliams 2005).

Figure 4-4. Graphical Representation of How an ESPC Project Is Financed



Source: KCC (2008)

In Arkansas, SB 1091—codified as Arkansas Code Title 19, Chapter 11, Subchapter 12—was passed in 2005 in order to authorize state agencies to enter into guaranteed energy cost savings contracts and to provide procedures for bid proposals, evaluations, and contract awards. The statute notes that "a state agency may enter into a guaranteed energy cost savings contract in order to reduce energy consumption or operating costs of government facilities [...]" and that the term of the contract may not extend beyond twenty years. The Arkansas Department of Finance and Administration (DFA) has posted an ESPC procurement and implementation flowchart on its Web site that elaborates upon the procurement, implementation, and monitoring of installed energy-saving measures.[21] In Arkansas, the Office of State Procurement (OSP) in the DFA qualifies the pool of ESCO's that can provide services to state government agencies, who then select an ESCO, arrange an audit, negotiate the contract with assistance from the OSP, and implement the identified savings measures, which are then subjected to ongoing savings monitoring. ESCO employees responsible for installation of the savings measures must possess a valid Arkansas contractor's license.

Our medium case scenario is modeled to reflect the requirements mandated by HB 1663, so that, in existing state buildings, energy savings of 20% are realized by 2014 and 30% by 2017 using 2008 sales

[21] See http://www.state.ar.us/dfa/procurement/documents/flowchart_standard.pdf for more information.

as a baseline (as opposed to the 2007–2008 fiscal year), and that these savings ramp up to 50% by 2025. We also quantify the expected savings from the 10% savings requirement in all new or major-remodeled buildings, which we treat as 10% savings above the current Arkansas energy code.

Our high case scenario is also modeled to reflect the requirements mandated by HB 1663 except that increased involvement with ESCO's allows savings beyond the targeted dates to ramp-up more aggressively to achieve cumulative savings in existing buildings of 65% by 2025. For new or major-remodeled buildings, we again assume a 10% savings requirement above the current code.

Weatherization of Severely Energy Inefficient Homes

Weatherization is the critical first step in improving the overall efficiency of a home. Most weatherization programs address a home's heating and cooling system as well as the envelope. Tightening the home envelope minimizes a home's heating and cooling loads so that any HVAC system upgrades are much more likely to be properly sized and perform at their peak efficiency. Sealing air leaks; adding thicker insulation in walls, ceilings, and roofs; and installing more efficient doors and windows are the primary targets when tightening the home envelope, which generates both short- and long-term savings, keeping energy bills low while also improving safety and comfort.

The Arkansas Weatherization Program

On July 2, 2007, Arkansas' seven electric and natural gas IOU's jointly filed the Arkansas Weatherization Program (AWP), concluding that a jointly-funded program would "overcome barriers to the success of individual utility weatherization programs," such as limited utility experience with weatherization programs and inefficient utility administration of smaller, individual weatherization programs (Docket No. 07-079-TF). The AWP is administered by the Central Arkansas Development Council with the fifteen weatherization service providers in the federally-funded Weatherization Assistance Program ("Weatherization Network") acting as the primary point of contact with customers. The Weatherization Network is also responsible for delivering all AWP energy audits and weatherization measures to customers, collecting customer co-payments, and paying third-party contractors and vendors. The Arkansas Community Action Agencies Association supports and coordinates Weatherization Network activities and the Arkansas Department of Human Services' Office of Community Services monitors quality by conducting project audits on 10% of the homes serviced.

Typically weatherization programs are directed at low-income homeowners, as these households on average spend a greater percentage of their income on energy relative to their wealthier counterparts, in part because the homes low-income families occupy tend to be more dilapidated and porous. In Arkansas, however, a previous Arkansas Supreme Court decision ruled that the PSC has no specific authority delegated by the Legislature to approve programs targeted to low-income customers, which has created uncertainty around whether such programs would be prohibited (Arkansas Gas Consumers, Inc. v. Arkansas Public Service Commission, 188 S.W.3d 109, 354 Ark.37). To overcome this limitation, eligibility for weatherization assistance funded through utility rates is targeted towards "severely energy inefficient homes," which, because of the link between income and the structural integrity of homes, should still manage to capture a significant portion of the market.

The Quick Start phase of the AWP began October 1, 2007 and ended December 31, 2009. During that time the program expected to weatherize 1,100 homes per year at an average cost of $3,000 with the AWP contributing up to 50% of the cost of services. The influx of ARRA funding has increased the average allowable cost to $6,500, so the 50% cost-share is not necessarily still true in practice. Customers of the program must be purchasing energy from at least one participating utility, and participating utilities pay up to around $1,000 except for all-electric homes, where the utility payment can reach upwards of $2,000. This includes costs for the audit, weatherization service, and 14% for program administration. Although the program is not specifically directed towards low-income customers, those that qualify for the federally sponsored Weatherization Assistance Program (WAP) are allowed to use DOE funds for their AWP co-payments, as well as for any costs in excess of $3,000. The maximum spending amount is capped at $5,000 for any one home, though any costs in excess of the first $3,000 are the responsibility of the customer.

The Arkansas Weatherization Assistance Program

Arkansas' other vehicle for weatherization is the DOE-funded Weatherization Assistance Program (WAP), which, unlike the AWP, is targeted specifically towards low-income homeowners up to 200% of the federal poverty level. The 2010 AR WAP State Plan reports that over two years it plans to weatherize 500 homes using federally appropriated DOE funds of $1.6 million and Low-Income Home Energy Assistance Program (LIHEAP) funds of $3.4 million, at a maximum average of $6,500 per home. About 15% of the LIHEAP funds will be leveraged for capital intensive efficiency measures. Additional funding for the AR WAP was appropriated through the *American Recovery and Reinvestment Act* (ARRA), amounting to $48 million to be used over a three-year period (April 2009–April 2012). At an average cost of $6,500 per home, the additional ARRA funds will help to weatherize an additional 5,700 homes, or around 1,900 homes per year.

Moving Forward with Comprehensive Weatherization Programs in Arkansas

As the AWP settles into its comprehensive phase, the definition of which will be fleshed out by the PSC and the pertinent parties over the next several months, it is important to consider a few issues. First, the supplemental funding from ARRA, which is more than 10 times greater than the funding the AR WAP has received historically, has required a tremendous amount of ramp-up that has most likely adversely affected the AWP because the agencies responsible for administering and implementing the program, such as the Weatherization Network, as well as local contractors, initially did not have enough hands to satisfy the demand generated by these two programs. In fact, one utility in Arkansas has already chosen to implement its own weatherization program in addition to its funding of the statewide AWP because the number of homes weatherized in its territory did not nearly meet the expectations of the goals as they were filed with the PSC.

Progress, then, will depend upon balancing the two programs as well as capitalizing on the momentum generated by the stimulus funding. Maintaining the number of homes weatherized annually once the ARRA funding has dissipated in 2012 will require a significant amount of funding that is unlikely to materialize for several years, a level which will depend in part on the maximum amount of money Arkansas is willing to spend on each home ($3,000 vs. $6,500). This funding will have to come from a mix of federal funds (WAP), state appropriations (WAP), and utility investments (AWP). In order to fully ramp-up and sustain the WAP and AWP programs, ACEEE encourages the state legislature to consider supporting higher budgets for the WAP, while greater investment from utilities would be a welcome boon to the AWP program. Fortunately, the resources to meet demand for weatherization services will already have expanded as a result of the demand generated by ARRA.

Second, as mentioned above, there is uncertainty concerning the Commission's authority to approve low-income energy efficiency programs. As a matter of sound, equitable public policy, ACEEE recommends that legislation should be considered that would specifically authorize the Commission to approve such programs. It is a well-known fact that low-income households spend a greater percentage of their income on energy relative to their wealthier counterparts, in part because the homes they occupy are generally more dilapidated and porous. Targeting severely inefficient homes, while reaching a sizable portion of the low-income market, allows wealthier homeowners to tap into a resource they may not necessarily need in order to weatherize homes that have become inefficient for reasons other than a lack of resources.

Our medium case scenario assumes that the AWP is continually built upon and improved over the course of the study. After the weatherization of 1,100 homes each of the first two years, we assume that the AWP ramps up to an annual weatherization of 1,600 homes by 2015 and sustains that annual target for the remainder of the analysis. We use the annual cost and savings estimates for the AWP taken from the July 2, 2007 filing in Docket No. 07-079-TF. The AWP estimated that annual electricity savings from weatherizing 1,100 homes would amount to 9.94 GWh and annual natural gas savings would reach 51.5 BBtu, at a two-year program cost of $7.5 million. Savings and costs increase proportionally with the number of homes weatherized, so that through 2025, about 27,000 homes in Arkansas are weatherized, generating savings of almost 100 GWh and over 760 BBtu.

Our high case scenario is modeled to reflect the weatherization goals targeted by the AR WAP through the leveraging of additional funds from ARRA. Around 5,700 homes were targeted for weatherization over a three-year period (2009–2012) in the ARRA 2009 WAP State Plan, or 1,900 per year, and an additional 500 per year in the DOE-funded WAP. We assume that funding is appropriated in order for the AWP program to ramp-up towards the targets set with the ARRA funding, so that 2,400 homes are being weatherized annually (1,900 plus 500) for the entire analysis period, with costs based on the AWP program and increasing proportionally with the number of homes weatherized. Again, savings and costs increase proportionally with the number of homes weatherized, so that through 2025, about 38,000 homes in Arkansas are weatherized, generating savings of almost 140 GWh and 1,100 BBtu.

Manufactured Homes Initiative

There are approximately 190,000 manufactured homes in Arkansas, representing 15% of the total housing units in the state (Economy.com 2010). Despite the fact that these homes are generally smaller than site-built homes, their energy costs can often be much higher. In fact, manufactured homes can be about 25% more energy intensive than those that are site-built. Additionally, many of the manufactured homes in use today were built before 1976 when the HUD code (the federal code mandating the minimum standard for manufactured housing) was enacted. In Arkansas, about 50% of manufactured housing was built prior to 1976.

Replacing pre-HUD code homes with new ENERGY STAR models can save an average of 6,200 kWh per year and 175 therms of natural gas annually (Levy 2009). Many pre- and post-HUD code homes are also excellent candidates for cost-effective efficiency retrofits including duct sealing, insulation improvements, and HVAC upgrades. But while the vintage of manufactured homes makes them an attractive target for weatherization, in many cases the homes are dilapidated to the extent that weatherization is not always cost-effective. Full replacement of the most inefficient manufactured homes may be more economical but the cost of replacing a home can price many potential customers out of the market.

One challenge to administering efficiency programs for the manufactured housing stock involves the income "sandwich." Currently the state WAP and the utility-funded AWP are the only means for owners of manufactured housing to get weatherization assistance, and only occupants with incomes equivalent to 200% or less of the federal poverty limit can qualify for WAP while the AWP only targets severely inefficient homes. Homeowners with the means to afford a new home can benefit from an ENERGY STAR-certified home with a heat pump. Thus, there is a segment of the market that falls into the middle of these to categories—they do not qualify for low-income assistance and can neither afford a new home nor make the necessary modifications to make their homes more energy efficient. Although the AWP can capture a portion of this market, the AWP resources are limited and the vintage of Arkansas' housing stock—about 53% of the housing stock is over 30-years old—means that owners of manufactured housing are in heavy competition for assistance with owners of other housing types.

Options for Servicing Manufactured Housing

Programs to help owners of manufactured housing weatherize or fully replace their inefficient homes have been gaining a lot of recognition recently. The ENERGY STAR Mortgage Program is largely responsible for the growth of these programs. The ENERGY STAR program is a public-private partnership directed by the Energy Programs Consortium (EPC)[22] and in collaboration with the DOE, the U.S. Environmental Protection Agency (EPA), and state energy and housing agencies, with support from several private

[22] Please visit http://energyprograms.org/energystar/overview.html for more information.

foundations. The goal of the program is to help homeowners obtain competitive, affordable financing for energy efficiency improvements that generate significant energy and, therefore, economic savings. The EPC works to approve all lenders in the state that wish to offer ENERGY STAR mortgages. Homeowners are given additional financial benefits beyond the energy savings, such as discounted mortgage rates, reduced loan fees, assistance with closing costs, and other benefits.

Maine was the first state to implement the program, directing it towards owners of pre-1976 manufactured housing.[23] The pilot program is still in its nascent stage, though participants have reported as much as 50% savings from ENERGY STAR-certified housing units. The Maine program targets low-income homeowners, for which utility funding is prohibited under Arkansas law. But pre-1976 manufactured homes are extremely inefficient, so such a program established in Arkansas would generate significant energy savings and help owners of these homes save a considerable amount of money on their heating and cooling bills.

South Carolina recently began offering a 100% sales tax exemption on manufactured housing as well as a $750 income tax credit. The state also leveraged funding from ARRA to develop a manufactured housing retrofit and evaluation program, which is administered jointly by the South Carolina Energy Office (SCEO) and the Office of Economic Opportunity, in coordination with the SC Technical College System, the SC Department of Commerce Workforce Program, and the Central Electric Cooperative of South Carolina. Over three years, this program will assess the efficacy of efficiency retrofits for low-income residents of manufactured housing, with goals to weatherize 200 homes, provide efficient roof retrofits for 200 homes, retrofit 200 homes with efficient heat pumps, and install ENERGY STAR appliance upgrades for an additional 200 homes (SCEO 2009).

Our medium scenario assumes a three-year pilot program beginning in 2010 that weatherizes/replaces 300 homes over the course of the pilot. The number of homes serviced ramps up by 100 homes per year to 500 per year in 2015 where it remains for the period of the analysis, for a total of about 6,500 homes serviced. We assume weatherization is able to generate electricity savings of 20% and natural gas savings of 10%, given that electric load of manufactured housing is generally much greater than natural gas.

Our high case scenario assumes again a three-year pilot program beginning in 2010 that, in this scenario, weatherizes/replaces 600 homes over the course of the pilot. We assume a slightly more aggressive ramp-up in this scenario, so that 1,000 manufactured homes are serviced annually by 2015, which is sustained for the remainder of the analysis, for a total of about 13,000 homes replaced over the course of the study. We again assume electric and natural gas savings of 20% and 10%, respectively.

Industrial Initiative

Manufacturing is the largest sector in Arkansas' economy, accounting for 15–20% of its gross state product, 37% of its electricity use, and 55% of its natural gas use. While this sector can be difficult to address in terms of energy efficiency policies and programs, it is crucial to improving employment and energy efficiency in the state. An effective statewide program will require leadership and collaboration between the government, industry leaders, and the education system.

Based on discussions with a broad range of stakeholders involved with the manufacturing sector, we propose a government/utility/industrial collaborative we are calling the "Arkansas Efficient Manufacturing Initiative." The goal of the initiative would be to address the three key barriers to expanded industrial energy efficiency identified by the stakeholders:

[23] Please visit http://www.mainehousing.org/ENERGYProgramsDetail.aspx?ProgramID=62 for more information on its manufactured housing pilot program.

1. The need for assessments that identify energy efficiency opportunities;
2. Access to industry-specific expertise; and
3. The need for an expansion of the trained manufacturing workforce with energy efficiency experience.

The initiative would establish "Manufacturing Centers of Excellence" in the model of DOE's Industrial Assessment Center (IAC)[24] program, where university engineering students are trained to conduct energy audits at industrial sites. The IAC program is a highly respected program with a proven track record of reducing energy costs for manufacturers and training the next generation of energy engineers. While Arkansas has not had an IAC since the 1990s, manufacturers in the state are served by IACs in Louisiana, Oklahoma, and Mississippi. We recommend that an IAC-like "Center of Manufacturing Excellence" be established, possibly at the University of Arkansas, which once housed an IAC. Expanding beyond the IAC model, this center could establish satellite centers in other parts of the state, as well as partner with community colleges and trade schools to bring their students into the larger network centered around the local Center of Excellence. These nearby satellite centers would extend training and associated materials to the community college partners, and offer the opportunity for students to join the audits they conduct. This approach would allow training not just of engineers, but also technicians and equipment installers, both of which are essential to preserving energy efficiency savings in the long run.

Collaborating and networking with organizations such as the Southeast Energy Efficiency Alliance (SEEA), Arkansas Manufacturing Solutions (the local Manufacturing Extension Partnership, or MEP), the Arkansas Chamber of Commerce, and manufacturing trade associations, the Efficient Manufacturing Initiative could provide outreach to manufacturing companies that might not otherwise be aware of energy efficiency programs. Further collaboration with the Arkansas State Energy Office's industrial energy efficiency programs would let the program rely on existing infrastructure and expertise on sustainability, energy, and job creation.

This initiative would provide multiple benefits to the state:

- Meet the needs of Arkansas manufacturers for a trained technical workforce;
- Provide valuable real-world work experience to students interested in working in manufacturing energy management and equipment installation and operation;
- Meet the need of manufacturing facilities for reliable, knowledgeable, and affordable consultation with regard to their energy usage and opportunities for improved productivity; and
- Build capacity at educational facilities and in the MEP outreach efforts that connect Arkansas' manufacturers to the wealth of knowledge and proficiency that resides in the state.

Funding for this initiative could come from a variety of sources including from utility public benefit funds or state revenue sources. This initiative would also be able to leverage the resources and tools developed by the DOE, such as the Save Energy Now (SEN) program.[25] We also encourage the state to support an expanded federal manufacturing initiative similar to what has been suggested in recent Congressional discussions.[26] These proposals would represent an opportunity to leverage successful national efforts to benefit the state's manufacturers.

IAC program and implementation results recorded over the last 20 years show that this program could identify 10–20% electricity savings per facility and achieve a 50% implementation rate. Program costs for the IAC program are about $1 for every $10 saved by industry. We factor in another $0.25 per $10 saved to account for additional education costs. Under these assumptions we estimate cumulative savings of

[24] For more information on the IAC program, visit: http://iac.rutgers.edu/.
[25] For more information on SEN program, visit http://www1.eere.energy.gov/industry/saveenergynow/.
[26] See http://www.aceee.org/topics/iac.

between 10% and 15% of the industrial electric consumption and between 15% and 20% of industrial natural gas consumption by 2025. These savings take into account the ability of large industrial customers to self-direct, a policy consideration we discuss within the context of an EERS, and the savings they would generate, which are allowed to contribute to the utility savings targets.

Research, Development, and Demonstration Initiative

Several states support active research, development, and deployment (RD&D) programs designed to develop technologies appropriate to each state's climate, economy, and other resources. In order to assist with economic development efforts and to meet long-term savings goals, RD&D of new technologies is critical to sustain continued improvements in energy efficiency after currently commercialized technologies and practices are widely adopted. The Association for State Energy Research and Technology Transfer Institutions (www.asertti.org) is a membership organization dedicated to increasing the effectiveness of energy research efforts that contribute to economic growth, environmental quality, and energy security. ASERTTI collaborates on research projects with state, federal, and private partners, and also acts as a clearinghouse of sorts by sharing technical and operational information among its members and associates. Members of ASERTTI include federal research organizations, universities, state research organizations, and non-governmental organizations.

Establishing an RD&D center in Arkansas, along the lines of the New York State Research and Development Authority (NYSERDA), the Energy Center of Wisconsin, or the Iowa Energy Center, would give the state an independent entity that would engage in objective research, disseminate information, and provide education on energy efficiency technologies to businesses and policymakers. At NYSERDA, research projects span seven primary program areas: energy resources, transportation and power systems, energy and environmental markets, industry, buildings, transmission and distribution, and environmental research. Research projects in the Buildings R&D group alone over the past decade have helped small businesses introduce 40 new products, create over 300 jobs, increase New York product sales by $238 million, and achieve energy savings of about $160 million. NYSERDA's Industry R&D group focuses on distributed generation/combined heat and power, emerging technologies, process improvement and product development, and transmission and distribution (NYSERDA 2008).

The University of Arkansas' National Center for Reliable Electric Power Transmission (NCREPT), housed within the University's Engineering Research Center, has created a foundation to build upon for Arkansas' future RD&D center. NCREPT is a research center "involved in five areas of research that impact the realization of power electronics solutions," which includes: 1) power electronic design and modeling; 2) control algorithms for power electronics; 3) power electronics packaging; 4) power electronics testing; and 5) mixed signal integrated circuit design for the drive and control power of electronic interfaces. The applications of NCREPT's research include use in the power grid for solid state-protection devices and energy storage; and packaging solutions for high current, high voltage power semiconductor devices and applications; as well as the creation of a state-of-the-art test facility for advanced power electronic circuit and package designs.

Pursuing the creation of an RD&D center in Arkansas could dovetail the work already accomplished by the University of Arkansas and NCREPT. The center already houses a modern testing facility but is an entirely technically-focused institution. Arkansas should consider expanding the facility to increase the scope of its technical research to additional areas of energy efficiency.

The RD&D center should not be entirely under the auspices of the state government nor seen as simply an additional source of funding for academics. One of the primary goals of an RD&D center is to develop new technologies for commercialization, to be produced and sold by Arkansas manufacturers and retailers. ACEEE therefore envisions the program to include competitive grants to Arkansas manufacturers for development of promising energy-saving technologies as co-funded projects, where investments from private industry supplement state funding. Funding sources could include a combination of state grants, and foundation grants, as well as investments from utilities and private industry.

Rural and Agricultural Initiative

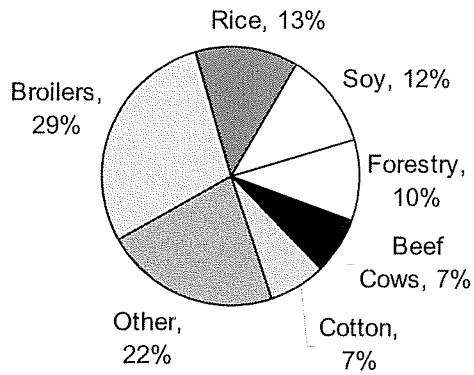
The agricultural sector in general is one of the most energy-intensive industries, relying on direct sources of energy, such as fuels or electricity to power farm activities, and on indirect energy resources contained in fertilizers or other agricultural chemicals. When energy prices are unstable or increasing, farmers and rural communities are impacted as agriculture becomes less profitable. Fertilizer, manufactured through an energy-intensive process, typically accounts for nearly 15% of total farm cash production expenses (USDA 2006).

In rural areas, such as most of Arkansas, updates to modernize the electric grid are expensive, and investing in on-farm energy efficiency or renewable energy is a more cost-effective option—a near-term resource available to respond to immediate energy challenges in rural communities.

A conservative analysis of the energy cost saving potential in the agricultural industry in the U.S. shows these savings to be over 34 trillion Btus and one billion dollars per year (Brown and Elliott 2005). This analysis covers the direct benefits from energy savings, but does not include non-energy benefits, such as increased financial stability due to reduced energy cost exposure. The study estimates significant savings by increasing energy efficiency in the production of several commodity crops—4.5 trillion Btu and $67.6 million per year in the poultry industry, and an amazing 17.1 trillion Btu and $167.7 million dollars per year in grain and oilseed operations.

Agriculture is an important industry in Arkansas, directly accounting for $3 billion dollars or 3% of Arkansas' GDP and according to the Arkansas Farm Bureau it impacts up to 20% of Arkansas' economy (Economy.com 2010).[27] It makes up almost 9% of Arkansas's industrial sector electricity use and 6% of Arkansas' industrial natural gas use, consuming 1,500 GWh and 5,000 BBtu, respectively, in 2008. Arkansas' agricultural sector includes several energy-intensive industries, including many large-scale poultry farms producing commercial broilers as well as beef operations in the central and western parts of the state, and rice, soy and cotton farms in the eastern counties bordering the Mississippi River. Arkansas ranks number one in the nation for rice production, and second for cotton and broiler production. Major sources of energy use for these types of livestock operations include lighting, ventilation, and heating/cooling. For rice, potential energy end-uses include irrigation, transportation, indirect energy such as fertilizer, and energy used for drying the rice.

Figure 4-5. Estimated Electricity Consumption of Arkansas Commodity Crops (2007)



Source: USDA 2007

Up until the 1990s, electric utilities, in conjunction with groups such as Advanced Energy and the cooperative extension service and experiment station system, provided extensive technical assistance on

[27] Arkansas Farm Bureau, http://www.arfb.com/

energy efficiency to these important agricultural markets (Elliott 1993). As electricity prices fell, utilities explored deregulation, and extension budgets fell during the 1990s, many of these efforts declined or were discontinued, mirroring a national trend. As a result, significant infrastructure for delivering energy efficiency faded.

In the past decade we have seen renewed interest in agricultural energy efficiency as energy prices soared and the U.S. Congress passed an energy title as part of the 2002 Farm Bill. Organizations specifically dedicated to improving farm and rural small business energy efficiency have emerged to fill this space. Existing energy efficiency programs are widening their focus to include agricultural energy efficiency issues and to provide more on-line and on-farm audits, as well as both technical and financial support. The Energy Title (IX) of the 2008 Farm Bill provides more funding than previous legislative efforts to the Rural Energy for America Program (REAP, formerly Section 9006), which provides technical assistance and audits, as well as grants and loan guarantees for energy efficiency and renewable energy projects to farms, ranches, and rural small businesses. Of 1,528 REAP awards for 2009 totaling over $86 million in grants and guarantees, only five were for projects within Arkansas, totaling $79,122 (ELPC 2009). REAP funding was initially restricted to rural agricultural applications; however, beginning in 2010 funding is available to all agricultural producers, regardless of location.[28] Although there is more money and awareness today, many states still lack the internal structure to aid their farmers, ranchers, and rural small businesses in leveraging these Farm Bill funds.

The 2008 Farm Bill also authorized a new program that will provide financial assistance toward increasing the energy self-sufficiency of rural communities. The Rural Energy Self Sufficiency Initiative will fund energy assessments, help create blueprints for reducing energy use from conventional sources, and install community-based renewable energy systems.[29]

The initiatives described below are meant to build capacity within the state of Arkansas in order to better provide energy efficiency-related knowledge, assessments, technical assistance, and funding for rural small businesses and agricultural operations.

I. Continue to Fund Development of the Arkansas Association of Resource Conservation & Development Council's Education Program Leveraging Additional Support from the Rural Electric Cooperatives, Investor-Owned Utilities, the Arkansas Farm Bureau, and the Extension Service

Over the last several years, the Arkansas RC&D Council has been conducting educational seminars across the state for Arkansas farmers on energy risk management, an issue that has become increasingly important as farmers face falling profits and rising energy costs. These seminars focus on several areas aimed at enabling farmers to reduce their energy costs, such as: identifying energy reduction opportunities; disseminating information on federal, state and utility financial incentives; elaborating on the benefits of energy audits and providers of this service; and assistance with applications for financial support.

Despite the success of RC&D's efforts and additional support from the federal and state level, much of Arkansas' rural and agricultural community is still unaware of the resources available to address energy costs, as well as an understanding of the potential benefits of energy efficiency and the risks associated with rising energy costs. It is critical that other state agencies participate and support the efforts of the RC&D Councils, in particular the Arkansas Department of Agriculture, the Arkansas Farm Bureau, the Arkansas State Extension Service, and the Arkansas Rural Electric Cooperatives. Supporting and augmenting this existing educational program to further disseminate information on energy efficiency best practices for farmers, ranchers, and rural small businesses will go a long way to ensuring the competitive edge of Arkansas farmers and rural businesses. This effort could also include a partnership with national

[28] Note: Small businesses still must be located in rural areas in order to receive funding.
[29] See Title VI, Energy Efficiency and Renewable Energy Programs for related program information:.

organizations, such as the Rural Electricity Resource Council (RERC)[30] or the USDA Rural Development.[31]

Several examples of state-specific educational programs exist that Arkansas can use as models to complement the efforts of the RC&D Councils. Southern California Edison utility runs an agriculture program that "promotes energy-efficient solutions for small and large farms, ranches, and dairies."[32] Their Web site provides information on a number of topics, including the Agricultural Technology Application Center (AGTAC). The latter, an "educational resource energy center," includes hands-on displays and exhibits that are open to the public; demonstrations of energy-efficient technologies; educational seminars and free workshops; and information regarding scheduling consultations with energy experts. AGTAC "connects customers to energy-related technology solutions that are energy efficient, positive for the environment and cost competitive."[33]

In the Midwest, the Iowa Energy Center funded a project looking at the "Development of an Energy Conservation Education Program for Iowa's Livestock and Poultry Industry."[34] The work products of the study will include a curriculum, with day-long training sessions for farmers, fact sheets, and a reference manual covering energy efficiency techniques, and a training regimen for extension agricultural field specialists, to assist with the distribution of the educational materials.

II. Further Leverage the USDA-REAP Program

Historically, Arkansas farmers have not utilized REAP funds as broadly as other states. To counter this trend, Arkansas utilities and extension services should make every effort to leverage the reauthorized USDA REAP program, which has $255 million dollars in mandatory funding for 2009–2012, to expand energy efficiency and renewable energy efforts throughout the state. Arkansas has been allocated $1.2 million in REAP funds to be distributed only to Arkansas farmers on a competitive basis. However, any portion of the allocated funds that are not used reverts back to a national pool that other states can bid for. ACEEE recommends that these entities provide on-site audits to farmers, ranchers, and rural small businesses as a preliminary step in the REAP application process, a service that the Arkansas RC&D Councils are already providing. Pinpointing areas where a farmer could save energy or implement an energy efficiency project is the first step toward identifying a successful REAP project.

To facilitate Arkansas' own efforts, the USDA recently announced an initiative to improve agricultural energy efficiency across the U.S., where 29 states will be given 1,000 energy audit evaluations during 2010, funded by $2 million from the Environmental Quality Incentives Program (EQIP) in fiscal year 2010. The initiative will also focus on the long-term development of Agricultural Energy Management Plans (AgEMP) for cost-effective implementation of the recommendations included in the audits. The program provides a cost share element where EQIP financial assistance can be used for up to 75% of the estimated incurred cost of implementation for the development of an AgEMP (USDA 2010). As a result, REAP applications in Arkansas are starting to swell and are likely to continue to rise (Bell 2010).

Mississippi is one of many REAP success stories. Poultry and egg production is the top agricultural commodity in Mississippi, with 2,800 producers and over $2 billion dollars in annual sales. Energy costs can reduce broiler producer's revenue by 20% due to inefficient energy use in poultry housing. The Mississippi State Poultry Science Department held educational workshops and provided application

[30] RERC's Web site, www.rerc.org, provides materials on energy efficiency and is a national center for information on rural electricity topics.
[31] http://www.rurdev.usda.gov/
[32] http://www.sce.com/b-rs/agriculture/
[33] http://www.sce.com/b-sb/energy-centers/agtac/
[34] http://www.energy.iastate.edu/Efficiency/Agricultural/cs/harmon_conserv.htm

assistance to producers, resulting in REAP funding for over 80 projects between 2003 and 2007, totaling around $3 million dollars.[35]

Alliant Energy operates a rebate and audit program for livestock and grain operations in Iowa, Minnesota, and Wisconsin. The program has been in effect for more than 20 years, with over four hundred participating farms in 2006 and annual savings of 8–10 million kWh. The program also assists customers in applying for USDA funding, offering assistance for both grant application and project implementation. Specifically, the on-farm audit identifies potential energy efficiency technologies to reduce energy usage, recommends efficient equipment specific to the operation, and provides information on available agricultural rebate programs. Operators can also earn cash back for purchasing recommended equipment.[36]

III. Create a Pool of Matching Funds for USDA Grants

To further promote the implementation of energy efficiency technologies and projects, Arkansas could consider establishing a pooling matching fund for these USDA-REAP grants. Availability of these funds could prove vital for successful REAP applications, as the USDA is considering availability of non-REAP funding as a criterion for the application ranking process. This funding pool could be established through the utilities, with savings from the efforts credited to the state REPS or EERS as suggested in this report, or from another funding source.

The New York State Energy Research and Development Authority runs the FlexTech program, providing cost-sharing of energy audits or feasibility studies of improvements and load management techniques that would save money on farmers' energy bills. The NYSERDA program is open to all sectors, but could be adapted in Arkansas to focus exclusively on agricultural operations as a tie-in with the USDA-REAP program funding. Across all sectors, FlexTech realizes $5 in energy savings and $17 in implementation/construction costs for every dollar spent on feasibility studies (Brooks and Elliott 2007).

Discussion of Enabling Policies

Energy Efficiency Clearinghouse

Arkansas' efforts to improve energy efficiency across all sectors of its economy, leveraged by a monumental increase in funding from ARRA, have led to the creation of numerous Quick Start programs offered by utilities and the state to various entities and individuals across the state. The short duration of these programs and the need to frequently augment and adjust them as they become more comprehensive means that participants will need a reliable resource in order to stay up-to-date on program changes. Establishing an online energy efficiency clearinghouse that retains all program information and updates its content regularly is a crucial element to the efficacy of these programs. Just as consumers need to be educated on the benefits and costs of energy efficiency, they must also be made aware of the existence of efficiency programs. An online clearinghouse can therefore be considered an educational tool, one that could have a considerable impact on the participation rates of these programs.

The AEO has already begun to set up an online clearinghouse for the industrial sector, which will provide tools, materials, papers, publications, and best practices that are helpful in identifying methods of reducing energy consumption. The AEO has leveraged almost $800,000 of its allotted stimulus funds to work on this project, which will be maintained by the University of Arkansas' Mechanical Engineering Department in collaboration with AR Manufacturing Solutions. Considering the prevalence of industrial

[35] http://farmenergy.org/success-stories/energy-efficiency/mississippi-poultry-growers
[36] More information on the Alliant Energy-IPL Farm Energy Audit program can be found on their Web site: http://alliantenergy.com/docs/groups/public/documents/pub/p014750.hcsp.

manufacturing in the state, the development of a Web site to house all efficiency program information as it pertains to Arkansas' industrial sector is a laudable first step. Upon completion of this project, the AEO should seriously consider expanding the Web site to include program information for the residential, commercial, and agricultural sectors. Efforts to disseminate this information should be careful not to be duplicative; in other words, if the AEO intends on expanding its efforts beyond the industrial sector, resources should be dedicated solely to bolstering the robustness of the AEO Web site as opposed to beginning anew elsewhere.

Many states have already developed robust online clearinghouses to disseminate program information to consumers. The more notable online clearinghouses include NYSERDA's New York State Energy Efficiency Clearinghouse (http://www.nyserda.org/clearinghouse/), which lists existing programs for K-12 schools, colleges and universities, local and state government, water and wastewater, and healthcare facilities. California also has an online resource called Flex Your Power, which is a statewide energy efficiency marketing and outreach campaign that is a partnership of California's utilities, residents, businesses, institutions, government agencies, and nonprofit organizations. The campaign includes a comprehensive Web site that provides program information by sector (such as rebates and incentives searchable by zipcode), an electronic newsletter and blog, and educational materials (http://www.fypower.org/). Primary funding for the two clearinghouses comes predominantly from System Benefit Charges, or in California's case, a Public Goods Charge.

In addition to the industrial clearinghouse currently under development, the AEO has already become a useful resource for statewide information on energy efficiency. *Energizing Arkansas*, for example, is a print and online publication that was created to provide policymakers, stakeholders, and interested citizens with timely, informative articles on the development of sustainable and renewable energy, energy efficiency, and energy policy in Arkansas. The AEO Web site provides some sector-specific information, but it could easily become a much more valuable resource if it were to be expanded upon to include program-specific, detailed information across all sectors. While this would require additional funding and personnel to expand and maintain, it would facilitate participation in state and utility programs by increasing awareness, thus enhancing the potential energy and economic benefits of these programs.

Evaluation, Measurement and Verification (EM&V)

The implementation of energy efficiency policies and programs must include a mechanism that emphasizes transparency and ensures success. This is one of the many issues remaining unresolved in the PSC's Notice of Inquiry into EE (Docket# 10-010-U), which identifies various information that should be included in the annual reports filed by utilities. The efficacy of efficiency programs will only be guaranteed if policymakers and consumers are aware of the benefits these programs are delivering, which, of course, also requires that these benefits be verified. EM&V methodologies can address this need by providing accurate, transparent, and consistent metrics—based on robust data—that assess the performance and implementation of an energy efficiency project or program.

EM&V serves several purposes: accountability, risk management, and improvement. To restate these purposes as questions:

1. *Do energy efficiency programs deliver the estimated savings?*

   Robust data on program impacts are needed to ensure that ratepayer and taxpayer dollars are being well spent and that programs are complying with any regulations.

2. *How certain are these savings?*

   The issue of risk management is also a central concern. Risk refers to the uncertainty surrounding the realization of expected savings from an efficiency project or program. EM&V methodologies should be sophisticated enough to assess, and maximize, the level of confidence of estimated savings, thereby lending credibility to energy efficiency as a viable resource.

An added risk is that, in the absence of robust data, governments or utilities may under-invest in relatively inexpensive energy efficiency programs and over-invest in more costly supply-side alternatives, as has been the case in the past. EM&V activities aim to provide this more robust data, thereby helping to avoid costly misallocation of public and private resources.

3. *What can be done to improve program performance in the future?*

   Most importantly, EM&V activities can—and should—be used to go beyond mere compliance by evaluating why a program had the effect that it did, with an eye to both improving existing programs and providing a sound mechanism for estimating savings from planned programs.

Existing EM&V Methodologies

It is important to make a distinction between energy efficiency *projects* and energy efficiency *programs* because of differences in the scope of measurement and methods of evaluation for each. A *project* is a single activity that takes place at a single location, such as the installation of energy-efficient lighting in an office. A *program*, on the other hand, is a group of projects sharing similar characteristics and taking place in similar locations, such as a state-level effort to increase efficiency in state-owned buildings.

Evaluation methodologies for projects have existed for many years, the most widely used of which include the following:

- Federal Energy Management Program (FEMP) M&V guidelines, Version 3.0 (FEMP 2008);
- International Performance Measurement & Verification Protocol (EVO 2007); and
- ASHRAE Guideline 14: Measurement of Energy and Demand Savings (ASHRAE 2002).

At the program level, efforts by the National Action Plan for Energy Efficiency Leadership Group, co-facilitated by the DOE and EPA, led to the development of the *Model Energy Efficiency Program Impact Evaluation Guide* (2007). This guide provides an in-depth discussion of EM&V implementation, noting four important steps in the EM&V process: 1) define the evaluation objectives, scale, and time frame; 2) select an evaluation method and define the baseline; 3) calculate gross and net savings; and 4) calculate co-benefits (according to policy objectives).

An inherent element of any attempt to advance energy efficiency is an independent entity dedicated to the evaluation, measurement, and verification of efficiency programs. A state's utility regulatory body, such as the PSC in Arkansas, is oftentimes the first entity thought of when delegating EM&V responsibilities. However, most public service commissions do not have the resources to lead this effort, which has led to problems in some states (e.g., evaluations have been delayed and very controversial since the California commission took the lead on evaluation), and so we recommend that the PSC not be laden with these additional duties. Nonetheless, the PSC must retain involvement in EM&V efforts. For example, if utilities are allowed to hire their own independent evaluators, the work of these third-party evaluators should be overseen by the PSC. Additionally, the PSC should hire its own expert to review utility evaluation plans and results. This process has worked well in Texas, for example.

Arkansas primarily relies on deemed savings values to estimate energy savings. Such an approach can work well as long as major programs are periodically subjected to more in-depth evaluations based on billing analysis and other techniques, and the results of the evaluations used to adjust the deemed savings values. The National Action Plan for Energy Efficiency (NAPEE) supports the use of deemed savings as a method of impact evaluation, but notes that it is frequently coupled with M&V and that "with the use of deemed savings there are no or very limited measurement activities and only the installation and operation of measures is verified. This approach is only valid for projects with fixed operating conditions and well-known, documented stipulation values" such as energy-efficient appliances and "lighting retrofit projects with well-understood operating hours" (EPA 2007c). Using deemed savings in the long term without periodic review and updating would therefore not be an ideal method for measuring the impact of home-envelope or HVAC improvements, which is considerably more dependent on the operating environment.

The transitory period between the end of the Quick Start programs and the beginning of the comprehensive phase of the programs would be an appropriate time to conduct these more in-depth evaluations. Also, analysis of some of the performance reports filed with the PSC revealed that some of the co-ops have not been reporting energy savings. We recommend that all Arkansas utilities, including the co-ops, be directed to report energy savings as well as the methodologies showing how savings were determined, on an annual basis. For the small co-ops, a few years delay may be appropriate to give them time to develop the appropriate tracking systems. Arkansas Electric Cooperatives, Inc. may be able to provide assistance to these efforts.

Financing Energy Efficiency

The upfront costs of investing in energy efficiency can often deter property owners who lack the capital to make investments and/or are reluctant to incur additional debt, especially during periods of economic uncertainty when consumer confidence is low. A primary goal therefore is minimizing the initial costs so that owners are encouraged to invest in efficiency retrofits. Below we discuss several options that will allow property owners to make these retrofits while ensuring that they maximize their savings.

An important facet common to many of these financing mechanisms is that the loan is attached to the property, so that the debt transfers to the new owner when the property is sold. Therefore property owners are only responsible for repaying the debt as long as they are benefiting from the efficiency improvements. The debt is also spread out over the course of several years, if not decades, which decreases the annual costs thereby increasing the annual net savings (energy bill savings minus loan payments) from the efficiency improvements substantially. Installing energy efficiency equipment and appliances also helps to increase the overall property value, and improve the cash flow of property owners (from reduced liability relative to the upfront costs). All three of the financing options discussed below would help create jobs immediately; jobs necessary to meet the demand for energy retrofits spurred by lower upfront costs.

- ***On-Bill Financing:*** This loan mechanism allows property owners to repay their debt through a fee on their electric bill. The loan can be financed either by the utility or a third-party financer, although the fee would be collected by the utility. The loan is attached to the property, so that the debt is transferred to the new owner when the property is sold. However, many utilities, including those in Arkansas, are reluctant to enter the loan business, whether as a lender or a collector, particularly if their own capital is involved. Even if utilities in Arkansas were open to on-bill financing, however, it may be considered a promotional practice and would therefore be prohibited.

  There are a few utilities in the U.S. that are now providing on-bill financing, such as Massachusetts Electric, Sempra Energy Utilities in CA, and United Illuminating (UI) in CT. The latter two focus on financing for small businesses, UI having one of the longest running on-bill financing programs in the country. Default rates have been exceptionally low: Sempra Energy reports only two defaults out of 350 projects while UI reports defaults less than 1% of 3,400 project installations. Other primary concerns have revolved around convincing customers that the savings estimated during the audit of the facilities could actually be captured, and that the demand for these programs far exceeds the caps on outstanding loans as established by the state governments (NSBA 2009).

- ***Property Tax Financing:*** A similar model to on-bill financing, except that instead of a fee included on the electric bill, the local government issues a surcharge, or lien, on the annual property taxes. The financing entity in this case would be the local government, which again could work with a third-party financer. The advantage of repaying the loan via a surcharge on property taxes is that property taxes can be deducted from the owner's income tax liability, further increasing the property owner's annual savings.

- ***Property Assessed Clean Energy (PACE) Bond Financing:*** A PACE bond or lien is a debt instrument attached to a residential, commercial, or industrial property that allows the owners to pay the expense of retrofitting their homes, buildings, or facilities through their property taxes. The bonds can be issued by municipal financing districts or other financing entities, of which the proceeds from the bonds are lent to property owners to finance energy retrofits (efficiency and renewables). The loans are then repaid over 15–20 years through annual assessments on property tax bills. The difference between PACE bond financing and property tax financing is that loans are made to property owners through the revenues generated by issuing bonds, as opposed to the government working with a third-party financer to offer loans. The Arkansas Development Finance Authority (DFA) is one potential entity to issue bonds for energy efficiency financing. The DFA administers funding in the form of tax exempt bonds through its series of program activities, which are divided into three main programs: Economic Development, Homeownership, and Affordable Rental Housing.

Fourteen states have already passed legislation authorizing PACE financing, California being the pioneer in 2008. ACEEE encourages Arkansas to introduce enabling legislation to create a market for these bonds. More information can be found at www.pacenow.org. Another possibility for the state to consider is that it can also offer technical assistance to municipalities interested in either property tax or PACE financing. In our discussions with Arkansas utilities, most were not interested in on-bill financing. Given all the work utilities need to do to get comprehensive programs underway, we believe that further discussion of on-bill financing at this point in time could be a distraction and therefore is a low priority.

Pennsylvania's Keystone Home Energy Loan Program (HELP) (www.keystonehelp.com) is one example of a well-developed, successful financing program. The program does not follow any of the financing mechanisms highlighted above; rather, it is a loan program supported by various state agencies and administered by AFC First Financial Corporation, one of three approved Fannie Mae Energy lenders in the U.S. Keystone HELP provides households low-interest loans between $1,000 and $35,000 for varying degrees of retrofits, from HVAC upgrades to whole house improvements. Contracted work can only be completed by an Approved Keystone HELP Contractor, of which there are over 1,600 in Pennsylvania.

Lost-Revenue Recovery/Incentives

Reducing total electricity and natural gas consumption provides customers lower energy bills, but can be a bane for utilities as lower sales mean lower revenues. Naturally there is concern from IOU's and their shareholders that, over time, dwindling revenues could impede utilities' ability to provide energy services due to decreased earnings or financial margins. To counter this phenomenon, IOU's have expressed their interest in pursuing lost revenue recovery and financial incentives in order to provide a return on their efficiency investments, which can be done through lost-revenue recovery, decoupling, performance-based incentives, and/or some other rate mechanism (EPA 2007c).

Utility spending on energy efficiency programs can impact the financial position of a utility in three ways: 1) through the direct costs of the programs; 2) through reduced revenues due to falling sales; and 3) through the return on investment on supply-side resources guaranteed by traditional utility regulation. Failure to recover the direct costs of efficiency programs means utilities lose the equivalent of those costs from their overall earnings. Falling revenues from lower sales hamper the ability of utilities to pay their fixed costs, such as paying off capital costs. Under traditional utility regulation, utilities are provided a return on their investment in supply-side resources, so spending on efficiency programs is money diverted from these capital investments that provide utilities with a return on their equity. To encourage utilities to invest in energy efficiency, all three of these issues should be addressed because neglecting to do so puts utilities in a relatively weaker financial position, dissuading them from pursuing energy efficiency further.

Lost-Revenue Recovery in Arkansas and Alternative Options

Arkansas already addresses the first issue by allowing utilities to recover program costs in rates on a monthly basis. In their initial filings for approval of the quick start programs, all utilities included requests for an energy efficiency cost recovery rider (EECR) for cost recovery, all of which were subsequently approved by the PSC. Utilities are also permitted to seek a true-up of the costs when they file their annual reports on the performance of their efficiency programs. Guidelines for cost recovery and other facets of Arkansas' utility-sponsored efficiency programs are codified in the PSC's Rules for Conservation and Energy Efficiency Programs.

The second issue, lost-revenue recovery, is an important issue to the state's utilities. Apart from the EECR, utilities are exploring other mechanisms for addressing the lost-revenue issue. As of July 2007, Arkansas' natural gas utilities currently have decoupling in place (known as the Billing Determinant Adjustment [BDA] mechanism). Decoupling, by removing the link between sales and profits, allows utilities to recover fixed costs if sales go down and prevents overcollection of fixed costs if sales go up. The Arkansas gas utility tariff allows utilities to adjust on an annual basis if the fiscal year revenue in the residential and small business classes is lower than the authorized revenue determined previously.

An alternative to decoupling is a lost revenue adjustment mechanism (LRAM) for energy efficiency programs. Under this approach, energy savings are estimated and multiplied by the fixed cost portion of rates, allowing utilities to recover these fixed costs. The LRAM adjustment is fairly simple. However, an LRAM adjustment goes just one way, so if utility sales increase due to robust economic growth, the utility may overcollect for fixed costs, since the LRAM allows them to collect for lost sales at the same time the extra sales associated with robust economic growth allows them to collect some or all of these same fixed costs. Also, an LRAM can make determining the energy savings achieved by energy efficiency programs more contentious, as every kWh or therm saved results in direct income to the utility. Entergy has proposed a Formula Rate Plan in its current rate base proceeding that purportedly would remove such risk, however ACEEE has not thoroughly reviewed the calculations and did not attempt to verify this claim (Docket #09-084-U).

The third issue is providing utilities with an economic incentive for successful implementation of energy efficiency programs. More than thirty states now offer such incentives to utilities. The most common approach is to calculate the net benefits of programs (lifetime benefits of energy savings minus utility and consumer costs) and allocate a small portion of these benefits (e.g., 10%) to shareholders, leaving the rest (e.g., 90%) for ratepayers. Other approaches include allowing utilities to put efficiency investments in their ratebase and earn a rate of return on them, or identifying fixed payments to shareholders upon successfully reaching specific program performance milestones. Regardless of the approach, in most but not all states with incentives, utilities need either to reach or to come close to program goals (e.g., kWh savings) before incentives are paid (for example, incentives kick in upon reaching 80% of the savings target). Also, incentives are commonly capped at some level above the targets (e.g., 130% of targets earns the maximum incentive) (EPA 2007b). It is important, though, that any incentives that are offered should be done so early, i.e., concomitantly with the establishment of utility efficiency programs. Providing these incentives early in the process, as opposed to delaying them until several years after the utility programs become effective, sends a signal to utilities that their efforts and investments will not go unrewarded and thereby encourages them to pursue more aggressive investments in energy efficiency.

In Arkansas, Entergy has proposed a formula rate plan (FRP) to addresses the concurrent recovery of lost contribution to fixed costs within the context of a comprehensive annual review of Entergy's costs. The FRP also includes a proposed shared savings mechanism, where Entergy would share the net benefits resulting from its energy efficiency programs with its ratepayers. In July 2009, all three of Arkansas' natural gas utilities proposed the same financial incentive mechanism based on $/Mcf saved after reaching a certain percentage of the energy savings goal. Arkansas Oklahoma Gas pulled their utility financial incentive proposal later that summer, so that Arkansas Western Gas and CenterPoint Energy are the only natural gas utilities with proposals for financial incentives still in the midst of a regulatory proceeding.

While ACEEE does not support one specific mechanism for addressing lost-revenue recovery and shareholder incentives over others, we believe that the best results can be achieved by a combination of some recovery mechanism aligned with proper shareholder incentives. We do believe that the dual-directionality of decoupling makes it attractive to ratepayers. But LRAMs can be an alternative if they are limited only to a few years; beyond a few years, lost revenues need to be considered in the overall context of a rate case. ACEEE also believes that introducing shareholder incentives is an important complement to cost and lost revenue recovery. Ideally, these incentives would take the form of performance target incentives, where utilities are rewarded for the achievement of specific targets as well as going above and beyond those targets. Lackluster performance should not be rewarded.

Public Outreach

In Order No. 12 issued in Docket No. 06-004-R, the PSC called for "utilities to take actions jointly with the AEO to design, construct, and fund a statewide education program that has a consistent message promoting the efficient use of electricity and natural gas." The outcome of this order was the creation of the Energy Efficiency Arkansas (EEA) program, a statewide education and training program that is funded by utilities and administered by the AEO, and one of two energy efficiency programs that is jointly funded by all of Arkansas' investor-owned utilities.

According to the Memorandum of Understanding (MOU), the purpose of the EEA program is "to cost-effectively deliver relevant, consistent, and fuel neutral information and training that causes people to consume less energy through energy efficiency and conservation measures." To achieve these goals, the EEA targets four elements: 1) educational outreach and promotion—no cost/low cost measures (residential); 2) HVAC training and certification (residential and small commercial); 3) energy rater training and certification program (residential and small commercial); and, 4) information outreach in large commercial and industrial sectors.

Like most of the utility Quick Start programs, the initial phase of EEA ran between October 2007 and December 31, 2009, which means that the program is currently in a state of transition. According to the PSC's omnibus order issued February 3, 2010, the "comprehensive" EEA program was approved for the period of July 1, 2010 through December 31, 2012, "subject to possible modifications following the examination by the AEO and other stakeholders of possible enhancements to the Program." The process of defining what is meant by a comprehensive public education program is intended to transpire during the first half of 2010, with a report and recommendations to the PSC submitted by June 30, 2010.
How the AEO and utilities will expand upon the current program is an issue that should command a lot of attention. The one limitation in a public action program such as this is that these efforts may not be effectively sustained for more than 18–24 months because they target low-hanging fruit that is quick and relatively inexpensive to adopt. As a result, significant savings are realized in the first few years but tend to dissipate quickly thereafter. However, this by no means precludes education programs from providing benefits to consumers in the future. Focusing on low-cost measures is an economical way to get the program up and running, but these efforts should be expanded to feature long-term opportunities as well. Setting up an all-sector, statewide online clearinghouse is one way to facilitate expansion. See our discussion of this topic above.

So while low-cost/no-cost measures will be adopted fairly quickly, as the market for energy-efficient products grows and matures, technology will change and consumers will continue to need resources to help them stay abreast of recent developments. Similarly, information on available federal, state, and utility programs targeting energy efficiency through rebates or other incentives will need to be disseminated and updated over the years. Maintaining the flow of information to consumers through various print and electronic media, such as the EEA website, will be critical to increasing the saturation of energy-efficient appliances and equipment. This effort could dovetail with ACEEE's recommendation for a statewide clearinghouse for energy efficiency information, covered above. There will also be a need for increasing focus on how consumers can locate skilled and certified contractors, as elaborated upon in our discussion of our Workforce policy. Greater public awareness leads to greater demand for quality energy efficiency services, thereby enabling greater savings from other programs and policies.

Workforce Initiative

Energy efficiency is generally more labor intensive than are supply resources, so developing a well-trained, local workforce that can address efficiency issues across all market sectors is critical. We thus see workforce development as a necessary element of many of the initiatives proposed above. Advancing efficiency in all sectors and throughout the entire state will require a workforce with training in many aspects of EE including identification/assessment of efficiency opportunities, proper installation and quality assurance techniques. This means greater demand for trained installers, technicians, engineers, architects, evaluation professionals, building operators, etc. All must be empowered with general and detailed knowledge. Such investment in human capital will maximize the efficacy of efficiency programs while also providing additional benefit to the state's economy by creating new "green collar" jobs.

Workforce Training in Arkansas

The Energy Efficiency Arkansas program, one of the two quick start programs jointly funded by all of Arkansas' investor-owned utilities, includes training elements as part of its statewide education effort. The training elements include training and certification for HVACR technicians for residential and small commercial applications. The HVACR training program is a collaborative effort that brings together equipment manufacturers, distributors, the AR Department of Health, the HVACR Contractors Association, and the colleges in AR that currently offer HVACR programs associated with the Air Conditioning Contractors Association. A list of graduates from the program will be given to utilities for use in their other quick start energy efficiency programs.

The EEA program will also develop an energy rater training and certification program, also for residential and small commercial applications. The training utilizes the Residential Energy Services Network (RESNET) nationally recognized standard for certification, which provides certification for professional Home Energy Rater System (HERS). The EEA program held two HERS training sessions, one in 2008 and one in 2009, both of which were limited to 10 in-state attendees. The AEO established a group to help promote the effort, which included the AR Home Builders Association, the Department of Health, the HVACR Contractors Association, AR Builders Licensure Board, the AWP, and the ACAAA and area CAP Agencies.

Leveraging Stimulus Funding for Training

Funding from the *American Recovery and Reinvestment Act* has given Arkansas a unique opportunity to begin expanding and training its workforce in order to meet the increasing demand for energy efficiency services. Through Arkansas' SEP, the AEO has directed $3 million to building training centers of excellence throughout the state. According to the AEO website, goals include developing curricula, facilities and equipment to train residential energy auditors, raters and weatherization employees.

The Energy Efficiency and Conservation Block Grant (EECBG) program presents another opportunity for investing in Arkansas' workforce. EECBG provides competitive grants to units of local government, Indian tribes, states, and U.S territories. The AEO received $5 million in funding from EECBG that will be distributed to cities with populations under 35,000 and counties under 200,000. Applications are currently being submitted for this portion of the EECBG funding, with notifications of finalists being released in June 2010. The minimum grant award is $5,000 while the maximum is $750,000. The AEO also received $3.8 million in additional funding for its SEP via EECBG.

In addition to funding for smaller cities and counties, the ten largest cities and counties in the state will receive $10.5 million directly from the DOE. Part of the $10.5 in EECBG grants that are coming to the state directly from the DOE have already been awarded to two Arkansas two-year colleges, Pulaski Technical College and NW Arkansas Community College, which received $7.4 million to provide training for jobs related to energy efficiency, which will be administered by the AEO. The schools will split part of the grant and use the rest—about $5 million—to coordinate the development of mobile training units that will visit the state's other community colleges (Peppas 2010).[37]

Training Arkansas' Future Green-Collar Workers

Arkansas has several training programs for energy efficiency that have the potential to develop a number of certified technicians to meet the rising demand for energy efficiency services across the state. The key to continued success with these programs is a matter of expansion, which is predicated upon available funding once the ARRA funds run out. First, the structure of the EEA program is sound and, given more buy-in from utilities, could continue to be an invaluable resource. In other states, ACEEE has recommended the establishment of a collaborative that brings together state government, businesses, schools, and utilities in order to shape the curriculum offered to trainees. The EEA has already made this a reality by bringing together various state agencies, schools and associations across the state to take part in shaping the HVACR and HERS training programs. It is imperative to the efficacy of these training programs in the future that this group continues to collaborate so that the program is dynamic, responding to the needs of the market as demand for various services expands or changes.

Second, more buy-in from utilities, which can benefit immensely from hiring trained and certified technicians for their own programs, would expand the program and allow more Arkansans to participate, increasing the number of in-state, certified technicians and thereby enabling the implementation of energy efficiency across the entire state, from urban to rural districts. The EEA offered only two HERS training sessions over the quick start program period, enrolling only 10 trainees per session. Utilities should consider increasing their investment in this program so that training sessions are offered more frequently throughout the year, possibly once per quarter. Utilities should also consider, depending on the frequency that training is offered, allowing more trainees to attend each session. According to RESNET, there are only three businesses in Arkansas that are RESNET certified rater members, having "committed to RESNET that they will meet the high standards of ethics and quality" with their home energy raters.[38] These certified raters are all located in the northwest part of the state.

Energy Efficiency Policy Scenario Results

This section describes results from our policy analysis, which includes the estimated cumulative savings in 2025 that represent the portion of the savings identified in our cost-effective resource assessment that can be captured by the programs and policies we have recommended as well as our analysis of demand response. Readers should understand that various technological advancements and efficiency improvements, such as updated building codes, while not explicitly estimated, are factored into the analysis in that not all of the savings we identified in our cost-effective resource assessment are captured by these policies. Also, over the analysis period new technologies will be developed that will increase the amount of cost-effective savings beyond the levels in our energy efficiency resource assessment. Below we report the energy savings generated by programs and policies in both our medium and high case scenarios.

Results from the Medium Case Energy Efficiency Scenario

In total, by 2025 these policies and programs in our medium scenario can meet 13% of Arkansas' projected electricity needs and 14% of its natural gas needs. Contributions from Arkansas' cooperatives can add an additional 2% electricity savings by 2025, for a grand total of 15% savings of projected sales. Peak demand impacts from efficiency efforts alone reach around 13% reductions; combined with demand response efforts, total peak demand reductions reach 20% (see Table 4-5 and Figures 4-6, 4-7, and 4-8).

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[37] The other 18 cities and counties in Arkansas that were awarded grants directly from the DOE can be found on the DOE's EECBG website, though detailed information on the specific projects is not available. Visit http://www.eecbg.energy.gov/grantees/default.html for more information.

[38] Please visit http://www.natresnet.org/directory/raters.aspx for information on certified HERS raters in Arkansas.

See Appendix C for year-by-year estimates of energy savings (for years 2010, 2015, 2020, and 2025 only).

Table 4-5. Total Energy Savings in 2025 from Energy Efficiency and Demand Response in the Medium Case

Policies and Programs	**Electricity**		**Peak Demand**		**Natural Gas**	
	GWh	%	MW	%	BBtu	%
Energy Efficiency Resource Standard (EERS)						
Residential Programs	*972*	*1.8%*	*205*	*1.8%*	*3,487*	*2.1%*
Commercial Programs	*1,451*	*2.6%*	*305*	*2.6%*	*5,089*	*3.1%*
Utility Programs Subtotal	***2,423***	***4.4%***	***510***	***4.4%***	***8,575***	***5.2%***
Behavioral Initiative	*163*	*0.3%*	*34*	*0.3%*	*435*	*0.3%*
Weatherization of Severely Inefficient Homes	*98*	*0.2%*	*21*	*0.2%*	*764*	*0.5%*
Manufactured Homes Initiative	*20*	*0.04%*	*4*	*0.04%*	*4*	*0.003%*
Manufacturing Initiative	*1,789*	*3.2%*	*377*	*3.2%*	*3,942*	*2.4%*
RD&D Initiative	*723*	*1.3%*	*152*	*1.3%*	*3,686*	*2.2%*
Rural and Agricultural Initiative	*159*	*0.3%*	*34*	*0.3%*	*-*	*0.0%*
EERS Subtotal	***5,375***	***9.8%***	***1,132***	***9.8%***	***17,406***	***10.6%***
Building Energy Codes	1,068	1.9%	225	*1.9%*	3,266	*2.0%*
Combined Heat and Power (CHP)	103	0.2%	13	*0.1%*	-	*0.0%*
Lead by Example	467	0.8%	98	*0.8%*	1,706	*1.0%*
Demand Response	NA	NA	877	*7.6%*	NA	NA
TOTAL	**7,013**	**13%**	**2,345**	**20%**	**22,260**	**14%**
Savings from Cooperatives	**955**	**2%**	**NA**	**NA**	**NA**	**NA**
GRAND TOTAL	**7,968**	**15%**	**2,345**	**20%**	**22,260**	**14%**

Note: Percent (%) reductions are presented as a fraction of *projected* energy use in the reference case.

Figure 4-6. Share of Electricity Met by Energy Efficiency Policies in the Medium Case

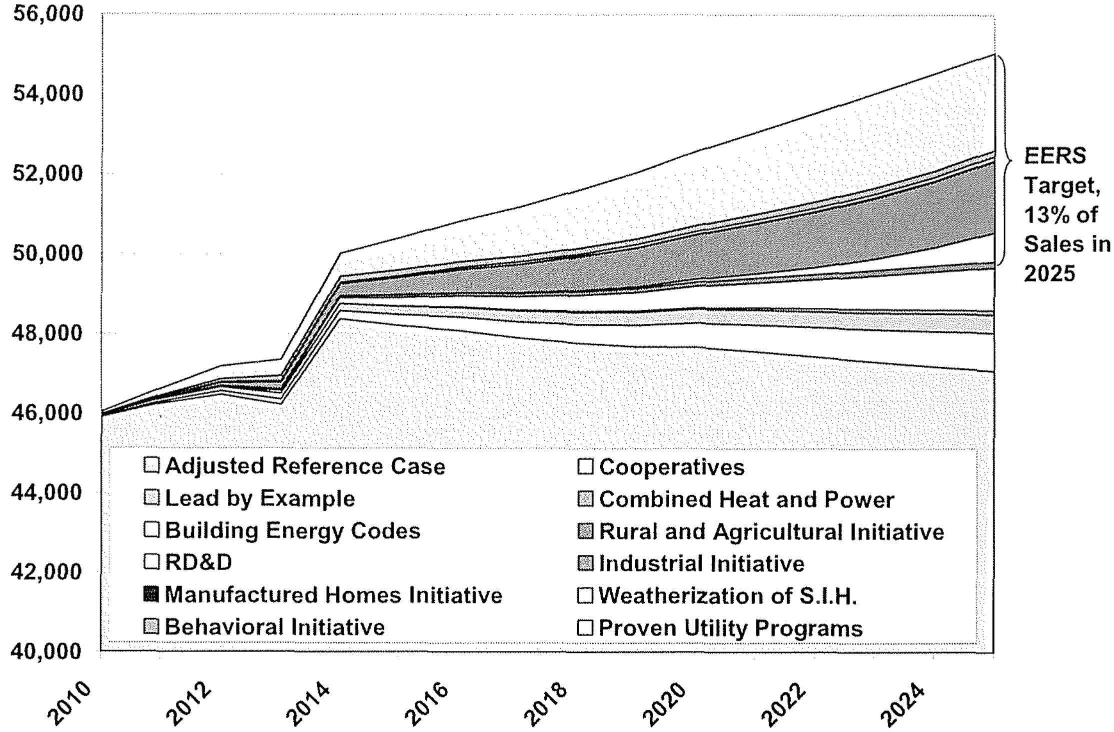


Figure 4-7. Share of Summer Peak Demand Met by Energy Efficiency and Demand Response in the Medium Case

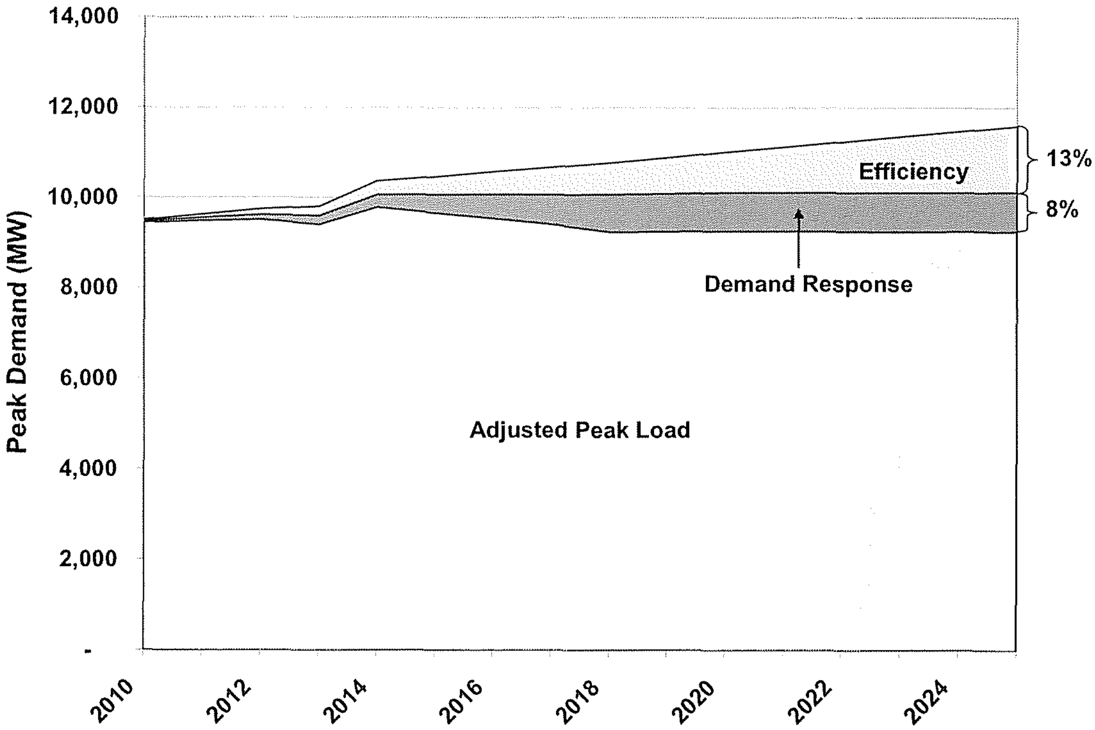
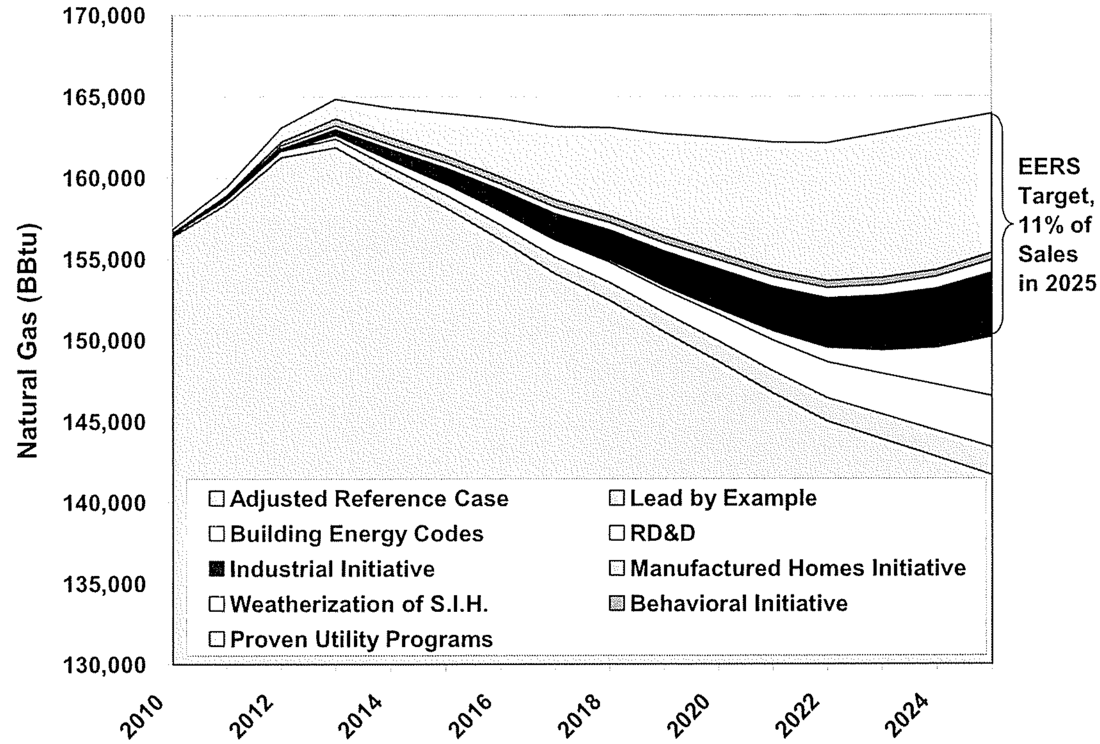


Figure 4-8. Share of Natural Gas Consumption Met by Energy Efficiency Policies in the Medium Case



Results from the High Case Energy Efficiency Scenario

In total, by 2025 these policies and programs in our medium scenario can meet 18% of Arkansas' projected electricity needs and 16% of its natural gas needs. Contributions from Arkansas' cooperatives can add an additional 4% electricity savings by 2025, for a grand total of 26% savings of projected sales. Peak demand impacts from efficiency efforts alone reach around 12% reductions; combined with demand response efforts, total peak demand reductions reach 29% (see Table 4-6 and Figures 4-9, 4-10, and 4-11). See Appendix C for year-by-year estimates of energy savings (for years 2010, 2015, 2020, and 2025 only).

Table 4-6. Total Energy Savings in 2025 from Energy Efficiency and Demand Response in the High Case

Policies and Programs	Electricity		Peak Demand		Natural Gas	
	GWh	%	MW	%	BBtu	%
Energy Efficiency Resource Standard (EERS)						
Residential Programs	*629*	*1.1%*	*132*	*1.1%*	*2,264*	*1.4%*
Commercial Programs	*1,282*	*2.3%*	*270*	*2.3%*	*4,478*	*2.7%*
Utility Programs Subtotal	***1,911***	***3.5%***	***402***	***3.5%***	***6,741***	***4.1%***
Behavioral Initiative	*290*	*0.5%*	*61*	*0.5%*	*776*	*0.5%*
Weatherization of Severely Inefficient Homes	*138*	*0.3%*	*29*	*0.3%*	*1,078*	*0.7%*
Manufactured Homes Initiative	*41*	*0.1%*	*9*	*0.1%*	*9*	*0.01%*
Manufacturing Initiative	*3,578*	*6.5%*	*753*	*6.5%*	*7,884*	*4.8%*
RD&D Initiative	*723*	*1.3%*	*152*	*1.3%*	*3,686*	*2.2%*
Rural and Agricultural Initiative	*159*	*0.3%*	*34*	*0.3%*	*-*	*0.0%*
EERS Subtotal	***6,839***	***12.4%***	***1,440***	***12.4%***	***20,173***	***12.3%***
Building Energy Codes	1,197	*2.2%*	252	2.2%	3,531	2.2%
Combined Heat and Power (CHP)	1,012	*1.8%*	135	1.2%	-	0.0%
Lead by Example	600	*1.1%*	126	1.1%	2,203	1.3%
Demand Response	NA	NA	1,360	11.7%	NA	NA
TOTAL	**9,648**	**18%**	**1,953**	**29%**	**25,907**	**16%**
Savings from Cooperatives	**2,429**	**4%**	**NA**	**NA**	**NA**	**NA**
GRAND TOTAL	**12,077**	**22%**	**1,953**	**29%**	**25,907**	**16%**

Figure 4-9. Share of Electricity Met by Energy Efficiency Policies in the High Case

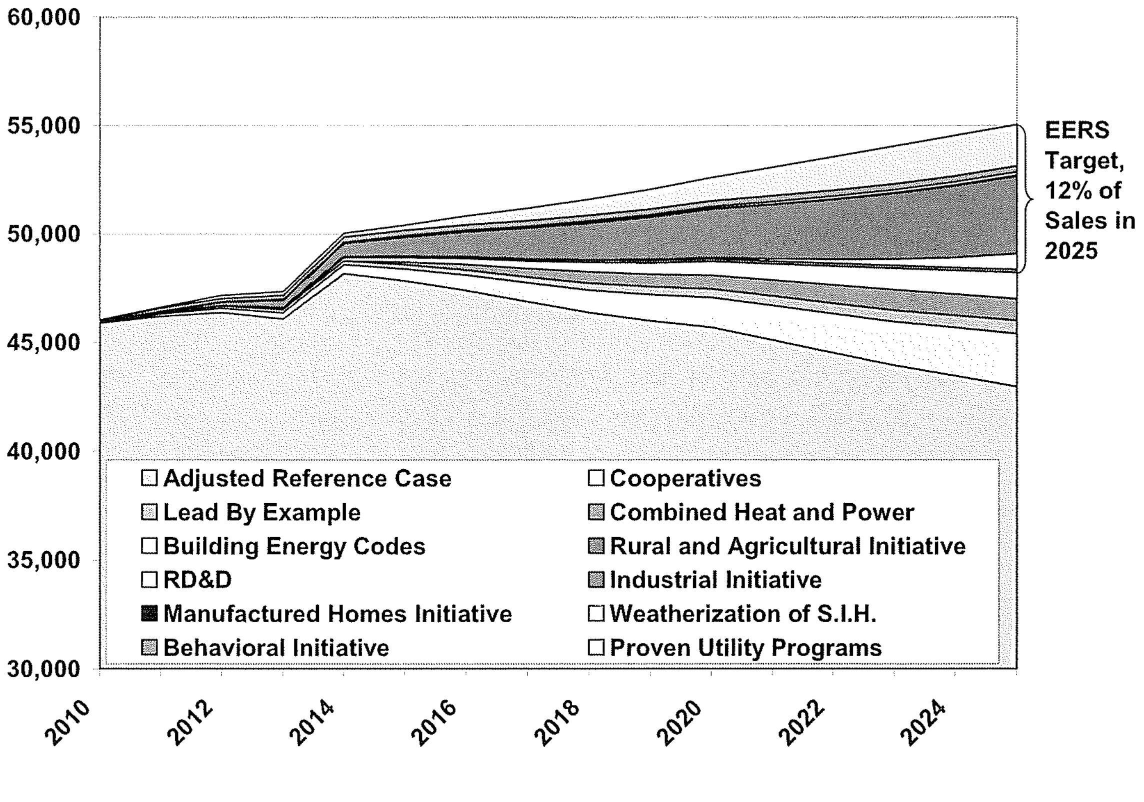


Figure 4-10. Share of Summer Peak Demand Met by Energy Efficiency and Demand Response in the High Case

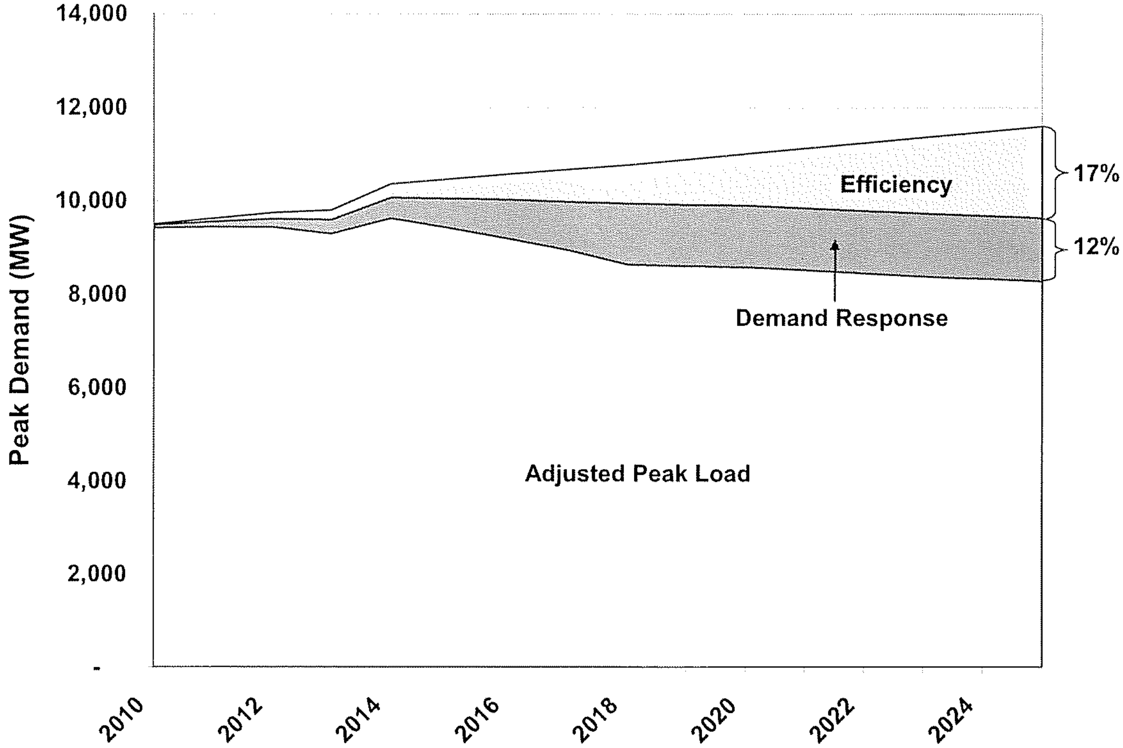
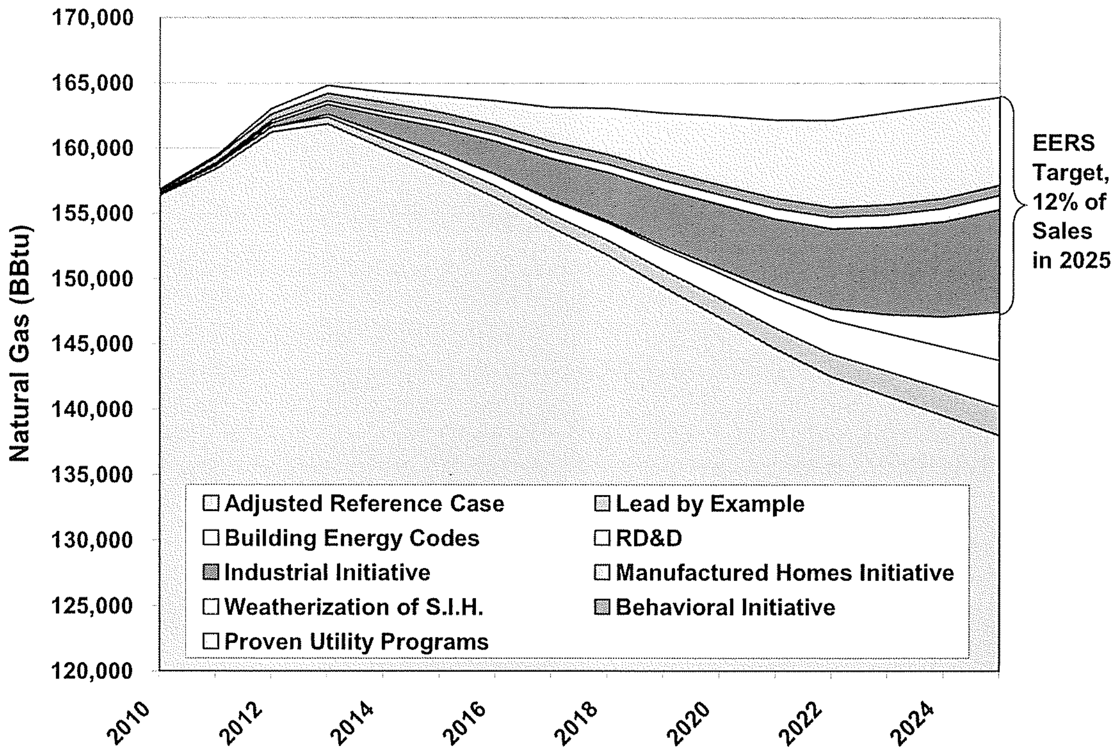


Figure 4-11. Share of Natural Gas Consumption Met by Energy Efficiency Policies in the High Case



Policy Investments and Program Costs and Benefits in the Medium Case

In this section we report the estimated costs and benefits from our recommended energy efficiency policies in the medium case scenario to determine their overall cost-effectiveness. There is no single way to determine cost-effectiveness; rather, there are multiple perspectives analysts take to estimate the cost-effectiveness of individual utility programs and portfolios of programs. As we discussed in our economic potential analyses for the various sectors, only cost-effective measures were considered for programs, a determination made by the comparison of the levelized cost of saved energy to the average retail price of energy (electricity or natural gas). We use the perspective of the participant because their investment is predicated on the benefits to participants being greater than the costs.

Here we report a net present value (NPV) analysis of costs and benefits to participants and society. Tables 22 and 23 show results from the Participant Cost test and the Total Resource Cost (TRC) test, respectively, with a breakdown of total costs and benefits (present value in 2007$) by policy type and by sector over the study time period (2010–2025). Readers should note that although the study time period ends in 2025, we estimate savings from the efficiency measures as they persist over the lifetime of each specific measure. Without accounting for these additional savings beyond the study timer period would yield a more conservative estimated of benefits and therefore a lower benefit/cost ratio.

The investments, or costs, required to run the recommended efficiency policies and programs in this scenario include the three following types: customer investments in efficient technologies or measures; program incentives paid to customers to cover the remaining technology/installation costs; and administrative or marketing costs to run programs or administer policies. The technology investments might include any combination of incentives paid to customers or direct customer costs. See Table 4-7 for a breakdown of the total estimated costs in the medium case scenario by benchmark year and Table 4-8 for a summary of cumulative costs by policy and program through the study time period (2010–2025).

Table 4-7. Annual Energy Efficiency Costs in the Medium Case (Million 2007$)

	2010	2015	2020	2025
Customer/Private Investments	$ 33	$ 147	$ 160	$ 236
Incentives Paid to Customers	$ 24	$ 64	$ 67	$ 26
Admin/Marketing Costs	$ 12	$ 27	$ 29	$ 20
Total Costs	**$ 69**	**$ 238**	**$ 256**	**$ 282**

Table 4-8. Energy Efficiency Costs in the Medium Case Scenario, by Policy (Million 2007$)

	Cumulative through 2025			Average Annual		
Policy/Program	**Customer/ Private Investments**	**Policy/ Program Incentives**	**Marketing/ Admin. Costs**	**Customer/ Private Investments**	**Policy/ Program Incentives**	**Marketing/ Admin. Costs**
Energy Efficiency Resource Standard (EERS)	$1,615	$854	$352	$101	$53	$22
Residential Programs	*$401*	*$380*	*$113*	*$25*	*$24*	*$7*
Commercial Programs	*$416*	*$393*	*$113*	*$26*	*$25*	*$7*
Behavioral Initiative	*$ -*	*$ -*	*$28*	*$ -*	*$ -*	*$2*
Weatherization of Severely Inefficient Homes	*$28*	*$47*	*$19*	*$2*	*$3*	*$1*
Manufactured Homes Initiative	*$8*	*$13*	*$5*	*$0.5*	*$1*	*$.3*
Manufacturing Initiative	*$468*	*$ -*	*$23*	*$29*	*$ -*	*$1*
RD&D Initiative	*$273*	*$ -*	*$41*	*$17*	*$ -*	*$3*
Rural and Agricultural Initiative	*$21*	*$21*	*$10*	*$1*	*$1*	*$0.6*
Building Energy Codes	$581	$ -	$20	$36	$ -	$1
Combined Heat and Power (CHP)	$10	$7	$6	$1	$0.4	$0.3
Lead by Example	$124	$ -	$12	$8	$ -	$1
TOTAL	**$2,330**	**$861**	**$390**	**$146**	**$54**	**$24**

Our macroeconomic analysis, discussed below, uses these cost assumptions to estimate the impacts of the recommended efficiency policies on the economy, including overall benefits to customers. Here we report a net present value (NPV) analysis of costs and benefits to participants and to society.

The results of the Participant Cost test, as shown in Table 4-9, indicate that the suite of energy efficiency policies creates a net benefit to participants over the study time period, with a benefit cost ratio of 3.0. This test takes the perspective of a customer installing energy efficiency measures in order to determine whether the participant benefits. The costs represent the costs to customers for purchasing or installing energy efficiency measures and the benefits are the savings on customers' energy bills due to reduced consumption, plus any incentives paid to customers. Again, this analysis takes into account costs through 2025 and benefits through the life of the measures. Without accounting for savings beyond the study time period, these policies and programs would still yield a benefit/cost ratio of 2.0, which means that even without capturing the full benefits of energy efficiency investments made by 2025, the policy scenario still achieves a net benefit.

Table 4-9. Participant Cost Test for Energy Efficiency Policies (2010–2025)

Policy/Program	NPV Costs	NPV Benefits	Net Benefit	B/C Ratio
Energy Efficiency Resource Standard	$ 1,182	$ 3,388	$ 2,207	2.9
Proven Residential Programs	*$ 377*	*$ 909*	*$ 531*	*2.4*
Proven Commercial Programs	*$ 409*	*$ 1,178*	*$ 769*	*2.9*
*Behavioral Initiative**				
Weatherization of S.I.H.	*$ 21*	*$ 89*	*$ 68*	*4.3*
Manufactured Homes Initiative	*$ 9*	*$ 19*	*$ 10*	*2.1*
Manufacturer Initiative	*$ 263*	*$ 850*	*$ 588*	*3.2*
RD&D	*$ 75*	*$ 243*	*$ 168*	*3.2*
Rural & Agricultural Initiative	*$ 28*	*$ 101*	*$ 72*	*3.6*
Building Energy Codes	$ 239	$ 701	$ 463	2.9
CHP	$ 24	$ 53	$ 29	2.2
Lead by Example	$ 44	$ 335	$ 291	7.6
Total	**$ 1,488**	**$ 4,478**	**$ 2,989**	**3.0**

* This policy was not evaluated because the only associated costs are program/administrative costs.

The Total Resource Cost (TRC) test, as shown in Table 4-10, evaluates the net benefits of the suite of *electricity* energy efficiency policies to the region as a whole. This test considers total costs, which includes investments in energy efficiency measures (whether incurred by customers or through incentives) and administrative or marketing costs. Benefits in the TRC test are the avoided costs of electricity, or the marginal generation costs that utilities avoid by reducing electricity consumption through efficiency, which were taken from the avoided energy resource costs developed by Synapse Energy Economics (see Appendix A). Because we only developed a set of electricity avoided costs for Arkansas, we evaluate here only costs and benefits related to electricity savings. We also do not take into account the affect of free riders because the TRC test measures the societal benefits as a whole; the impact of free-riders is more of a concern in utility cost tests. Nor do we take into account the affect of free drivers, or spillover benefits.[39] In terms of impacts on energy savings, we assume that on average these two effects roughly cancel each other out.

[39] In the context of public benefits or utility efficiency programs, "free riders" are those who would install an energy efficiency measure absent of any financial incentives, doing so because of the return on investment, but collect the financial incentives anyway. "Free drivers" are those that install energy efficiency measures because of the indirect effects of energy efficiency programs but do not collect the rebate or incentive (Heins 2010).

The TRC test, which shows an overall benefit/cost ratio of 2.5, suggests a net positive benefit to Arkansas from the implementation of these efficiency programs and policies. Without accounting for the benefits that persist after measures are installed in 2025, the Participant Cost test still yields a positive net benefit to participants, with a benefit/cost ratio of 1.5.

Table 4-10. Total Resource Cost (TRC) Test for Electric Efficiency Policies in the Medium Case (2010–2025)

Policy/Program	NPV Costs	NPV Benefits	Net Benefit	B/C Ratio
Energy Efficiency Resource Standard	$ 1,380	$ 3,193	$ 1,813	2.3
Proven Residential Programs	*$ 435*	*$ 618*	*$ 184*	*1.4*
Proven Commercial Programs	*$ 471*	*$ 957*	*$ 486*	*2.0*
Behavioral Initiative	*$ 16*	*$ 110*	*$ 94*	*6.9*
Weatherization of S.I.H.	*$ 34*	*$ 64*	*$ 30*	*1.9*
Manufactured Homes Initiative	*$ 12*	*$ 12*	*$ 0.1*	*1.0*
Manufacturer Initiative	*$ 275*	*$ 1,078*	*$ 803*	*3.9*
RD&D	*$ 103*	*$ 245*	*$ 142*	*2.4*
Rural & Agricultural Initiative	*$ 35*	*$ 109*	*$ 74*	*3.1*
Building Energy Codes	$ 251	$ 656	$ 406	2.6
CHP	$ 27	$ 60	$ 32	2.2
Lead by Example	$ 53	$ 325	$ 272	6.1
Total	**$ 1,711**	**$ 4,234**	**$ 2,523**	**2.5**

Review of Existing Arkansas Potential Studies

Our medium scenario estimate of 13% electric savings by 2025 from utility programs plus an additional 3% savings from building codes, EE in state buildings and CHP is higher than estimated in recent studies commissioned by SWEPCo and Entergy. Here we briefly explain the differences. Results from an assessment of energy efficiency opportunities in the South conducted by Georgia Tech and Duke University were also available, showing comparable results to those found in this study. We will discuss this in further detail below as well.

Southwestern Electric Power Company (SWEPCO)—*Energy Efficiency Potential Study (2009):*

An April 2009 report prepared by Frontier Associates found an achievable electricity saving potential of 3.4% in 2018 using incentives covering 65% of measure costs and 8.4% in 2018, using aggressive financial incentives (covering 90% of measure costs). This covers utility-operated programs and does not include building codes, appliance standards or CHP. By comparison, our estimate of savings from utility programs in 2018 is 5% savings in the medium case and 3.7% savings in the high case, relative to 2009 sales. Therefore, our savings estimates are similar, but SWEPCo estimates more aggressive financial incentives will be needed to reach these levels. Our estimates are based on states such as Vermont (profiled on p. 34) which has achieved 9% savings over nine years from utility programs, using customer costs (which includes incentives) that are 46% of the total measure cost. Another key difference between the SWEPCo study and ours is that we considered many more efficiency measures than they did, leading to a larger pool of efficiency opportunities to draw from without having to raise resort to very high financial incentives.

EAI—*Demand Side Management Potential Study (2009):*

An April 2009 report prepared for Energy Arkansas by ICF International estimated that 4% energy efficiency savings are possible by 2017 in their high case, with only 2.5% savings in the medium case and 1.4% savings in the low case. This is perhaps the lowest estimate of achievable savings we have seen, much lower for example than what we consider to be a very conservative study published by the Electric

Power Research Institute and the Edison Electric Institute which estimated 5-8% achievable electricity savings by 2020 (EPRI 2009). Reasons for the differences between Entergy's estimates and ours include:

- They appear to have included significantly fewer efficiency measures than we did. To provide just one example, our out-year savings include some emerging technologies whereas their analysis is based on only technologies that are widely available today.
- Their analysis eliminated measures that were not cost-effective based on a stream of avoided costs for 2010; for example, the avoided cost averaged 5.1 cents/kWh in 2010. We used 8.2 cents/kWh as our cutoff, based on the average retail price of electricity in 2009. However, few measures came close to our cutoff; most had lower costs.
- They applied a series of factors that reduced the energy savings potential due to technical feasibility and payback acceptance. We applied factors as well, but theirs appear to be much more limiting.
- They assumed much higher administrative costs than we did (e.g., 55% for most programs vs. an average of 14%).

Georgia Tech/Duke University—*Energy Efficiency in the South* (2010)

A study recently published by Georgia Tech and Duke University profiles the opportunities for energy efficiency, both electricity and natural gas, in the South through the year 2030. The study includes an analysis of the potential for energy efficiency in Arkansas alone, estimating the opportunity for cost-effective energy efficiency improvements across all sectors of the Arkansas economy, drawing on the results from the overall analysis. The analysis looked at the ability of nine energy policies to curb consumption growth, estimating that they could generate achievable savings of 7% of 2007 consumption by 2020. Sector-savings reach 10%, 15%, and 10% by 2020 in the residential, commercial, and industrial sectors, respectively, relative to projected consumption in 2020. Savings estimates for electricity and natural gas were aggregated and reported in terms of Btus.

The results from our policy analysis, which estimates the achievable potential for energy efficiency in the state, are comparable to those found in the GA Tech/Duke study. Aggregating savings estimated in our policy analysis from both electricity and natural gas showed that Arkansas could achieve overall savings of 10% of 2007 energy sales in 2020, with 13%, 13%, and 5% savings in 2020 for the residential, commercial and industrial sectors, respectively, as a percent of projected consumption in 2020. We are uncertain about the reason for the disparity in achievable savings estimated for Arkansas' industrial sector, as the policies analyzed in both studies appear to be fairly similar. If that is the case, likely the disparity in savings stems from assumptions of participation in the programs.

Review of Policy Recommendations from the Governor's Commission on Global Warming (2008)

In 2008, the Governor's Commission on Global Warming (GCGW), which was created through the signing of Act 696 of the Arkansas 86th General Assembly, released a report making 54 specific policy recommendations intended to reduce greenhouse gas emissions and address climate-, energy-, and commerce-related issues in Arkansas. The Commission included members from business, industry, environmental groups, and academia, the vast majority of which were appointed by the Governor. Members of the Commission were asked to vote on each individual policy, half of which were approved unanimously.

The policy recommendations spanned all sectors of the economy, i.e., the residential, commercial, industrial, and transportations sectors, and included recommendations directed at energy supply, land use, and agriculture, forestry and waste management. Most of the recommendations fall outside the scope of this report, but there were a number of policies directed at improving energy efficiency that also feature in our study.

For instance, most of the policies that were recommended by the Commission for the residential, commercial, and industrial sectors are recommendations that were made independently by ACEEE, which are covered in more detail in the following section. These policies include: improved building codes; utility and non-utility DSM (includes cost recovery); reduced energy use in state-owned buildings; public education and outreach; incentives to promote energy efficiency (low-income weatherization that includes incentives for manufactured housing); and, non-residential energy efficiency (combined heat and power). And although we did not analyze energy efficiency in Arkansas' transportation sector, historically ACEEE has recommended investments in energy efficiency in the transportation sector by means of smart growth, freight efficiency, and improved transit service and infrastructure.

It is worth noting that none of the recommendations for Arkansas' agricultural sector targeted energy efficiency explicitly. Agriculture is a major industry in the state; in fact, Arkansas is the nation's leader in rice production. But both the production of rice as well as poultry farming—Arkansas' other major source of revenue in the agricultural sector—are quite energy intensive, and ignoring the need for energy efficiency in the manufacturing processes for these products leaves a considerable amount of potential energy savings unaddressed.

Assessment of Demand Response

This section defines Demand Response (DR), assesses current DR activities in Arkansas, identifies policies in the state that impact DR, uses benchmark information to assess DR potential in Arkansas, and identifies barriers in the state that might keep DR contributing appropriately to the resource mix that can be used to meet electricity needs. The analysis concludes with identification of policy recommendations regarding DR.

Defining Demand Response

DR focuses on shifting energy from peak periods to off-peak periods and clipping peak demands on days with the highest demands. Within the set of demand-side options, DR focuses on clipping peak demands that may allow for the deferral of new capacity additions and enhance operating reserves to mitigate system emergencies. Energy efficiency focuses on reducing overall energy consumption with attendant permanent reductions in peak demand growth. Taken together, these two demand-side options can provide opportunities to more efficiently manage growth, provide customers with increased options to manage energy costs and develop least cost resource plans.

DR resources are usually grouped into two types: 1) load-curtailment activities where utilities can "call" for load reductions; and 2) price-based incentives, which use time-differentiated and/or dispatchable rates to shift load away from peak demand periods and reduce overall peak-period consumption. Interest in both types of DR activities has increased across the country as fuel input prices have increased, environmental compliance costs have become more uncertain, and the substantial investment in overall electric infrastructure needed to support new generation resources.

The summary of DR potential presented on Table 4-11 focuses on load-curtailment and backup generation and does not include savings resulting from price-based incentives. Residential load-curtailment typically involves direct load control (DLC) of air conditioners—although this can also cover appliances—as well as temperature offsets, which increase thermostat settings for a certain period of time. Commercial and industrial applications of DR focus on load control of space conditioning equipment, however this depends on customer size: self-activated load reductions are usually more prudent for larger customers. Backup generation for commercial and industrial applications involves generators with start-up equipment that allows them to come online with short notice from utilities, relieving the additional demand on the system during peak hours.

Rationale for Investigating Demand Response

DR alternatives can be implemented to help ensure that a utility continues to provide reliable electric service at the least cost to its customers. Specific drivers often cited for DR include the following:

- **Ensure reliability**—DR provides load reductions on the customer side of the meter that can help alleviate system emergencies and help create a robust resource portfolio of both demand-side and supply-side resources that meet reliability objectives.
- **Reduce supply costs**—DR may be less expensive per megawatt than other resource alternatives.
- **Manage operational and economic risk through portfolio diversification**—DR capability is a resource that can diversify peaking capabilities. This creates an alternative means of meeting peak demand and reduces the risk that utilities will suffer financially due to transmission constraints, fuel supply disruptions, or increases in fuel costs.
- P**rovide customers with greater control over electric bills**–DR programs would allow customers to save on their electric bills by shifting their consumption away from higher cost hours and/or responding to DR events.
- **Address legislative/regulatory interest in DR**–The State approved the Renewable Energy and Energy Efficiency Portfolio Standard (REPS) that considers DR to be an eligible activity for cooperative and municipal utilities.

Demand Response in Arkansas—Background

A sound strategy for development of DR resources requires an understanding of Arkansas's demand and resource supply situation, including projected system demand, peak-day load shapes, and existing and planned generation resources and costs.

Arkansas utilities serves a population of over 2.9 million, and generates approximately 53.3 million megawatt hours of electricity, that had a system peak load of almost 8,600 MW in 2007 (ACEEE base case for Arkansas). Electricity demand has grown an average of 3% per year since 1990, fluctuating moderately (EIA 2010b).

Arkansas has been and likely will continue to be a modest exporter of energy. Coal-fired plants in Arkansas supply about one-half of State electricity demand and rely entirely on coal deliveries via railcar from Wyoming (EIA 2010b).

Role of Demand Response in Arkansas' Resource Portfolio

The DR capabilities deployed by Arkansas utilities can become part of a long-term resource strategy that also includes resources such as traditional generation resources, power purchase agreements, options for fuel and capacity, and energy efficiency and load management programs. Objectives include meeting future loads at lower cost, diversifying the portfolio to reduce operational and regulatory risk, and allow Arkansas customers to better manage their electricity costs.

The 2005 Energy Policy Act provisions for Demand Response and Smart Metering has lead to a number of states and utilities piloting and implementing a Smart Grid, or sometimes referred to as Advanced Metering Infrastructure (AMI). Smart Grid is a transformed electricity transmission and distribution network or "grid" that uses robust two-way communications, advanced sensors, and distributed computers to improve the efficiency, reliability and safety of power delivery and use. For energy delivery, the Smart Grid has the ability to sense when a part of its system is overloaded and reroute power to reduce that overload and prevent a potential outage situation. Principal benefits of Smart Grid technologies for DR include increased participation rates and lower costs.

The growth of renewable energy supply (and plans for increased growth) can also increase the importance of DR in the portfolio mix. For example, sudden renewable energy supply reductions (e.g., from an abrupt loss in wind) may be mitigated quickly with DR.

Assessment of Demand Response Potential in Arkansas

Table 4-11 shows the resulting cumulative load shed reductions possible for Arkansas, by sector, for years 2015, 2020, and 2025. Load impacts grow rapidly through 2018 as program implementation takes hold. After 2018, the program impacts increase at the same rate as the forecasted growth in peak demand.

The high scenario DR load potential reduction is within a range of reasonable outcomes in that it has an eleven year rollout period (beginning of 2010 through the end of 2020), providing a relatively long period of time to ramp up and integrate new technologies that support DR. A value nearer to the high scenario than the medium scenario would make a good MW target for a set of DR activities.

The high scenario results show a reduction in peak demand of 639 MW is possible by 2015 (6.1% of peak demand); 1,322 MW is possible by 2020 (12.1% of peak demand); and 1,360 MW is possible by 2025 (11.8% of peak demand).

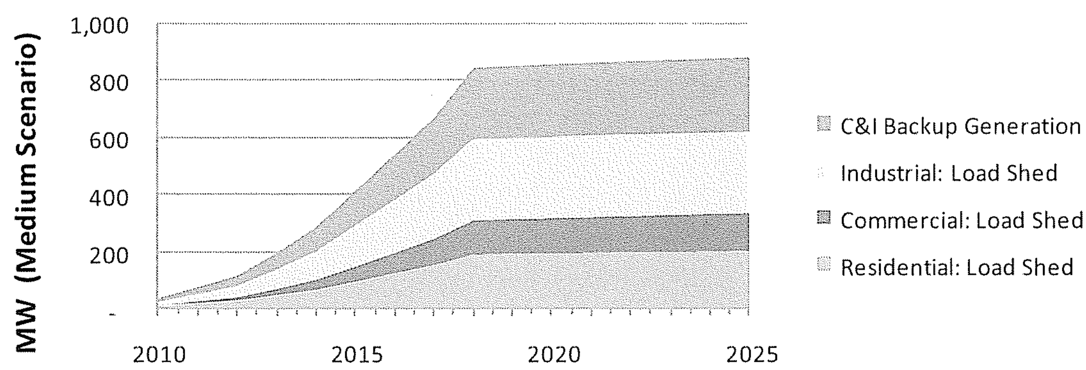
The more conservative medium scenario results show a reduction in peak demand of 412 MW is possible by 2015 (3.9% of peak demand); 853 MW is possible by 2020 (7.8% of peak demand); and 877 MW is possible by 2025 (7.6% of peak demand).

Table 4-11 Summary of Potential DR in Arkansas, by Sector, for Years 2015, 2020, and 2025

	Low Scenario			**Medium Scenario**			**High Scenario**		
	2015	**2020**	**2025**	**2015**	**2020**	**2025**	**2015**	**2020**	**2025**
Load Sheds (MW):									
Residential	55	116	120	92	193	201	129	271	281
Commercial	22	47	51	59	127	136	110	237	256
Industrial	62	125	125	140	281	280	248	500	498
C&I Backup Generation (MW)	91	189	195	121	251	260	152	314	325
Total DR Potential (MW)	230	477	491	412	853	877	639	1,322	1,360
DR Potential as % of Total Peak Demand	2.2%	4.4%	4.3%	3.9%	7.8%	7.6%	6.1%	12.1%	11.8%

Figure 4-12 shows the resulting load shed reductions possible for Arkansas, by sector, from year 2010, when load reductions are expected to begin, through year 2025.

Figure 4-12. Potential DR Load Reductions in Arkansas by Sector (Medium Scenario)



These estimates reflect the level of effort put forth and utilities are recommended to set targets for the high scenarios. These estimates are based on assumptions regarding growth rates, participation rates, and program design. These factors are discussed in Appendix D on Demand Response. In developing these DR potential estimates, the integration of DR with select energy efficiency activities was considered to help ensure that load impacts were not double counted. The estimated load reduction per program participant is conservatively estimated to account for increased energy efficiency in the future.

Recommendations

Arkansas has a small amount of existing DR, particularly DLC programs. Enabling technologies and DLC are found to be cost-effective for all customer classes in the state (FERC 2009). However, deployment of AMI is expected to occur in the state at a slightly lower-than-average rate (FERC 2009).

Key recommendations include:

- Appropriate financial incentives for Arkansas utilities either for programs administered directly by the utilities or for outsourcing DR efforts to aggregators. The basic premise is that a utility's least-cost plan should also be its most profitable plan. Whether adequate incentives are provided for the appropriate development of DR programs in Arkansas should be examined.

- Key programs that should be offered by Arkansas energy providers which can be designed within a 12-month period include:
  - Residential and small business AC direct load control using switches or thermostats (or giving customers their choice of technology).
  - Auto-DR programs providing direct load curtailment for larger commercial and industrial customers.
  - Callable interruptible programs with manual response to an event notification for larger commercial and industrial customers where auto-DR approaches are not acceptable to the customer or technically not feasible.
  - Aggressive enrollment of back-up generators in DR programs.

- Plan for at-scale programs through the rollout period. Pilot programs can be important in determining the appropriate design of cost-effective DR programs. However, there are established DR programs and technologies. Even with the unique circumstances in Arkansas, these programs can be designed for deployment at scale. However, this approach recognizes that the first year of program deployment and possibly the second year should be designed to test key design components as part of a program shakeout. The third year of a program that should represent an efficient design and an at-scale program. DSM programs are designed to be flexible and undergo year-to-year changes due to market, customer and technology factors. This will always be the case and the benefits of discrete pilot program can limit overall program participation for a number of years resulting in "lost DR MWs." The politics of DSM and diverse positions of parties can result in a compromise in the implementation of programs leading to a two to three-year pilot program. This can delay the delivery of DR at scale resulting in higher overall costs. The over-use of pilots that do not acknowledge the ability of a program roll-out to have at-scale deliver as its goal in year three, but to also have tests of design components and decision nodes built into the first two year of program rollout can result in "death by piloting" for attainable DR MWs. Also, a decision to run a pilot program must be based on the assumption that the program will not have enough flexibility in design and on-going decision nodes during the first two years to allow for the ramp up into full scale efficient deployment in year three.

- Load reduction programs typically have less need for pilot programs as the reductions are defined by the equipment and processes outlined by the program for each participant. Time differentiated pricing is a cornerstone of efficient electric markets and the design of these programs may need more pilot testing as the customer response to pricing is voluntary and not set (as often) by program design.

- Implement programs focused on achieving firm capacity reductions as this provides the highest value demand response. This is accomplished through establishing appropriate customer expectations and by conducting program tests for each DR program in each year. These tests should be used to establish expected DR program impacts when called and to work with customers each year to ensure that they can achieve the load reductions expected at each site.

- Arkansas has some history of time-differentiated rates. Pricing should form the cornerstone of an efficient electric market. Daily TOU pricing and day-ahead hourly pricing will increase overall market efficiency by causing shifts in energy use from on-peak to off-peak hours every day of the year. However, this does not diminish the need to have dispatchable DR programs that can address those few days that represent extreme events where the highest demands occur. These events are best addressed by dispatchable DR programs.

- It is important that the DR programs be integrated with the delivery of EE programs. Many gains in delivery efficiency are possible by combining and cross-marketing EE and DR programs. These can include new building codes and standards that include not only energy efficiency construction and equipment, but also the installation of addressable and dispatchable equipment. This can include addressable thermostats in new residences and the installation of addressable energy management systems in commercial and industrial buildings that can reduce loads in select end-uses across the building/facility. In addition, energy audits of residential or commercial facilities can also include an assessment of whether that facility is a good candidate for participation in a DR program through the identification of dispatchable loads. Furthermore, building commissioning and retro-commissioning EE programs that are becoming popular in many commercial and industrial sector programs have the energy management system as a core component of program delivery. At this time, the application of auto-DR can be assessed and marketed to the customer along with the EE savings from these site-commissioning programs.

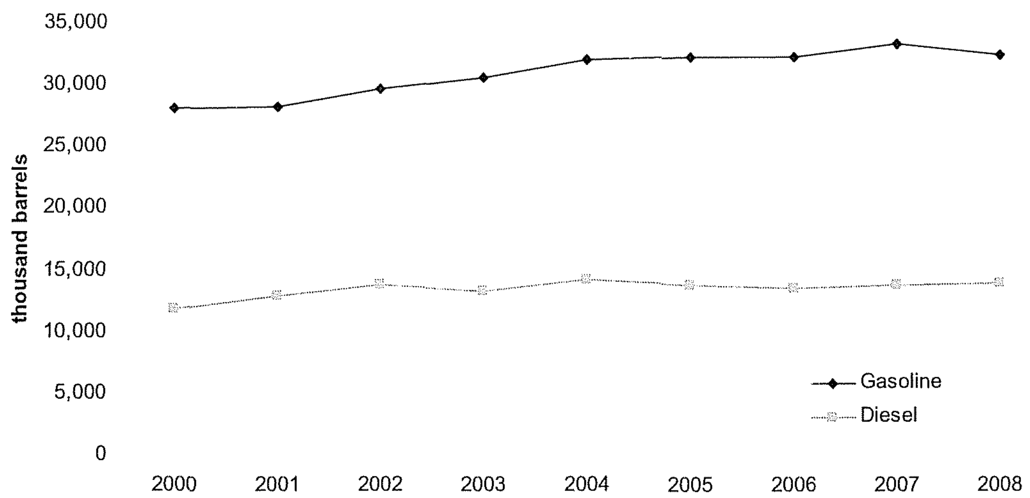
- Customer education should be included in DR efforts in Arkansas. There is some perceived lack of customer awareness of programs and incentives were programs do exist. In addition, new programs will need marketing efforts as well as technical assistance to help customers identify where load reductions can be obtained and the technologies/actions needed to achieve these load reductions. Also, high-level education on the volatility of electricity markets helps customers understand why utilities and other entities are promoting DR and the customers' role in increasing demand response to help match up with supply-side resources to achieve lower cost resource solutions when markets become tight.

Chapter Five: Transportation Efficiency

Background

Arkansas's population is expected to grow by almost 13% by 2025, reaching approximately 3.3 million people over the next 15 years. With this large increase in population, the state will continue to face a number of transportation-related challenges. In 2008, the transportation sector consumed 292 trillion Btus of energy, 26% of total energy use in the state, and about 1% of total transportation energy consumption in the United States (EIA 2010a).[40] The 23% cumulative growth in Arkansas' transportation fuel consumption of the 1990s slowed slightly to 17% over the past decade, but even this more moderate trend increases the state's vulnerability to high fuel prices and its emissions of greenhouse gases and other criteria pollutants (see Figure 5-1).

Figure 5-1. Historical Gasoline and Diesel Consumption in Arkansas, 2000–2008



Sources: EIA (2010b), ACEEE analysis

Arkansas' geographic and demographic diversity presents a challenge to statewide transportation policy. Policies applicable to urban, high density areas may not be suitable for large swathes of the state consisting of rural communities.

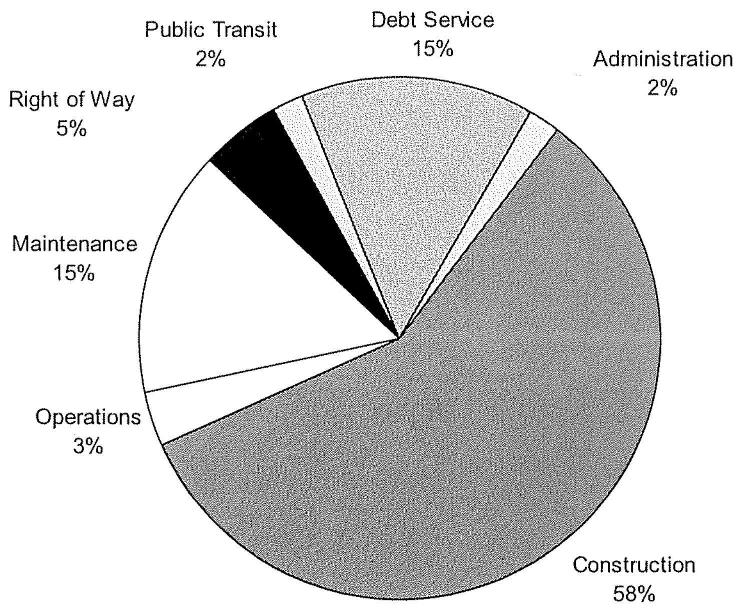
For decades, the vast majority of the state's transportation dollars have been poured into large-scale highway projects, while transit and other non-auto modes have received little. Figure 5-2 below shows that highway construction and highway maintenance occupy the bulk of the Arkansas State Highway and Transportation Department's (AHTD) annual budget while alternative modes of transportation are allocated only 2% of total expenditures.

Increasing congestion and rising fuel prices have made addressing transportation challenges a growing priority for the state and several jurisdictions are focusing on public transit as a necessary form of relief (Metroplan 2009a, NWARPC 2006). Arkansas already has a number of laws in place to provide communities with a means to increase funding for public transit. Title 26 of the Arkansas Code (26-73-111) allows counties to levy a .25% local option sales tax to provide funding for a purpose of their choosing, such as public transit, provided it is approved by voters. In 2005, the state legislature passed

[40] Arkansas' population is just under 1% of the total population of the U.S.

Act 2275 (revised in 2007 as Act 389), the Regional Mobility Authority Act, which allows counties and other jurisdictions to create a regional mobility authority (RMA), essentially a government agency, that may levy taxes in order to supplement federal and state funding of any kind of surface transit system. However, to date only one RMA has been established and few, if any, jurisdictions have levied taxes to fund public transit. Despite these foundational policies, many additional steps are still required to attain an energy-efficient transportation sector in the state. This chapter will discuss a number of strategies that can be implemented to take advantage of energy efficiency potential in the transportation sector.

Figure 5-2. AHTD FY2008 Expenditures by Category



Source: AHTD (2008)

Reference Case

All gasoline and diesel savings reported in this chapter are relative to the "business as usual" transportation scenario, or reference case. In this section, we report the major assumptions underlying the reference case for the time period of this study—2009 to 2025.

We calculated gasoline consumption in Arkansas as a product of population, vehicle miles traveled (VMT) per capita, and fuel consumption per mile. To project future consumption, we used VMT forecasts from the Arkansas State Highway and Transportation Department (AHTD 2010a), county and state population projections from the University of Arkansas at Little Rock's Institute for Economic Advancement (AIEA 2010), and ACEEE estimates of expected average fuel consumption rates for the U.S. vehicle stock. ACEEE estimates of gasoline consumption are almost equivalent to actual gasoline consumption as reported by the Energy Information Administration (EIA) for 2007. Diesel consumption figures for 2000–2007 were obtained from the EIA's State Energy Data System and then projected forward until 2020 using regional diesel consumption growth rates from EIA's *2010 Annual Energy Outlook*. The reference case also uses county-level projections of population growth from AIEA to determine average residential density by county.

The transportation reference case takes into account the increase in federal fuel economy standards that were adopted by the U.S. EPA and the National Highway Transportation Safety Administration (NHTSA) in 2010 for model years 2012 to 2016. Those standards require a 34.1 mile-per-gallon average for cars and light trucks sold nationwide in 2016. The strategies outlined in this chapter will produce gasoline savings above and beyond savings achieved through these federal programs. The Energy Independence and Security Act (EISA) of 2007 requires that fuel economy standards be set for medium- and heavy-duty trucks as well. No assumptions of increased fuel economy have been made for these vehicles, however, because the level of standards to be set is unknown.

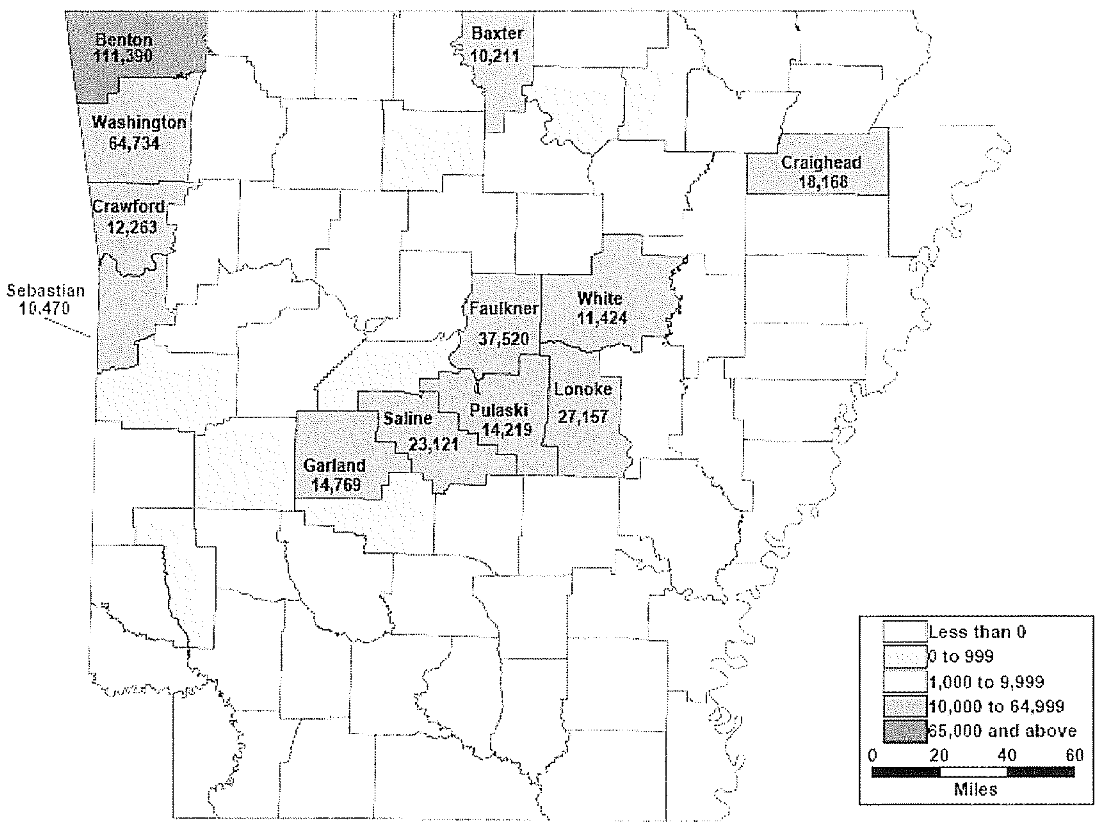
It should be noted that, while there is substantial uncertainty regarding future trends in vehicle purchases, vehicle miles per capita, and other key factors in transportation energy use, the difference between fuel use in the reference case and fuel use in the policy scenarios will be fairly insensitive to modest changes in these trends.

Energy Efficiency Policy Analysis

Policy Scenario Descriptions

The two scenarios for our transportation efficiency policy analysis are shown in Table 5-1. The medium case scenario described below includes policies that Arkansas can achieve cost-effectively. The high case scenario is generally more aggressive in its attempt to capture a larger portion of the energy efficiency potential in Arkansas; in other aspects the high case reflects instead an assumption of greater efficacy for a given measure than assumed in the medium case. Figure 5-3 highlights the high growth counties referenced in the matrix below in the medium case.

Figure 5-3. High-Growth Counties in Arkansas, 2010–2025



Following the policy discussions and estimates of the resulting energy savings, we estimate the costs and fuel savings ($) that can be realized from their implementation.

Table 5-1. Matrix of Transportation Efficiency Policies in the Medium and High Case Policy Scenarios

	Transportation	Medium Case Scenario	High Case Scenario
1	Clean Car Standard	148 g/mile CO_2 by 2025	148 g/mile CO_2 by 2025
2	Pay-As-You-Drive Insurance	Mileage-based insurance for high growth counties in the state	Mileage-based insurance statewide
3	Transit Expansion / Concentration of Urban Development	Transit expansion plus half of metro growth to transit stops; assume 15% reduction in VMT from doubling density around rail stations	Transit expansion plus half of metro growth to transit stops; assume 25% reduction in VMT from doubling density around rail stations
4	Reduced Light-Duty and Heavy-Duty Speeds	Stringent enforcement of current highway speed limits	Stringent enforcement of current highway speed limits
5	Heavy Truck Efficiency Package	Incentives for SmartWay-type improvements for long-distance trucks registered in Arkansas	Mandated SmartWay-type improvements for long-distance trucks registered in Arkansas
6	Freight Intermodal Investments	7% diversion of long-haul truck freight to rail, and 2% to marine	10% diversion of long-haul truck freight to rail, and 3% to marine
7	Truck Stop Electrification	Low-interest loan programs for truck stops in Arkansas	Low-interest loan programs for truck stops in Arkansas
8	Efficient State Vehicle Fleet*	State procurement policy of best-in-class	State procurement policy of best-in-class, with 10% hybrid purchase and 33% vehicle downsizing
9	Vehicle Electrification	Policy discussion only	

*We did not analyze the potential costs of this policy and, as a result, it was not included in our macroeconomic analysis discussed in the following chapter.

Energy Efficiency Policy Scenario Results

This section describes results from our policy analysis, including estimated total annual fuel savings from transportation efficiency policies in 2015 and 2025 for both the medium and high case scenarios. More detailed results, assumptions, and analysis of costs and benefits are shown in Appendix C.

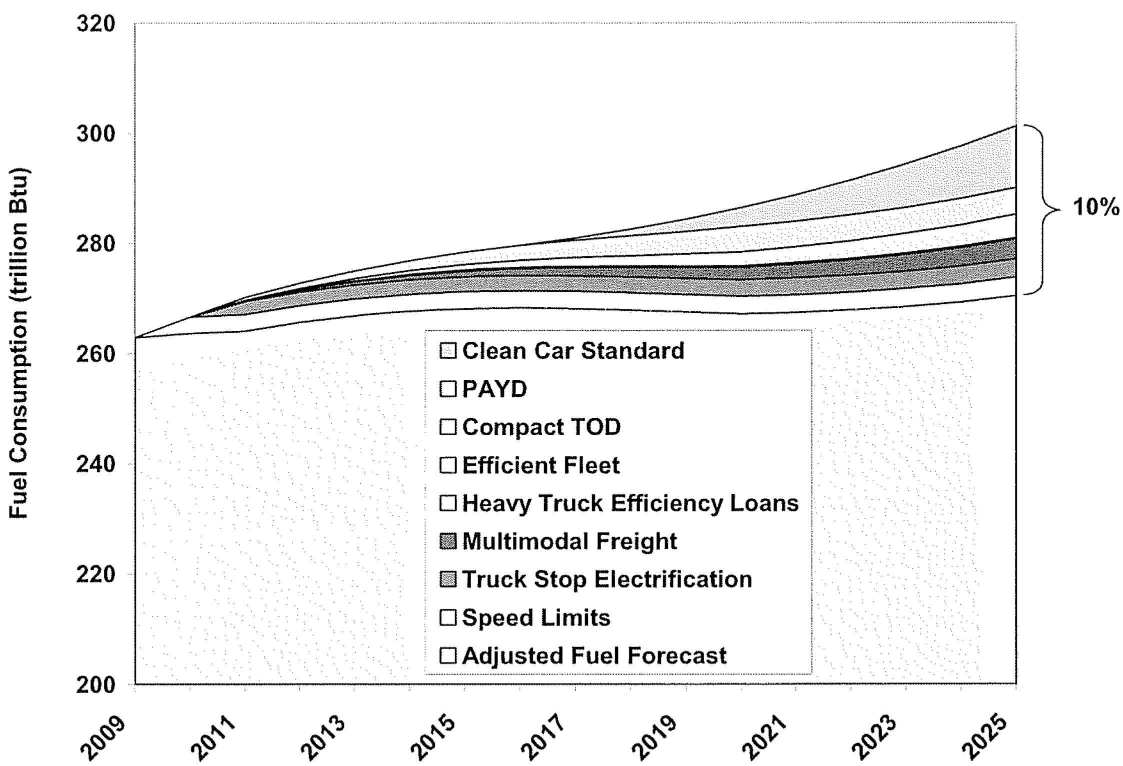
Medium Case Scenario

The estimated total fuel savings in 2015 and 2025 for the medium case scenario are shown by policy/program in Table 5-2. Under this scenario, we estimate that Arkansas will see combined fuel savings of approximately 10% by 2025 (see Figure 5-4).

Table 5-2. Summary of Transportation Savings by Policy or Program in the Medium Case Scenario

	Annual Transportation Savings by Policy (thousand barrels)	2015	2025	Savings in 2025 (%)
1	Clean Car Standard	0	2,130	5.6%
2	Pay-As-You-Drive Insurance	432	920	2.4%
3	Transit Expansion / Concentration of Urban Development	77	705	2.2%
4	Light-Duty Speed Limit Enforcement	399	419	1.1%
5	Efficient State Vehicle Fleet	7	9	<1%
	Total Gasoline Savings	**915**	**4,183**	**11.3%**
6	Heavy Truck Efficiency Package	29	35	0.2%
7	Truck Stop Electrification	554	680	3.8%
8	Freight Intermodal Investments	180	619	3.5%
9	Heavy-Duty Speed Limit Enforcement	171	196	1.1%
	Total Diesel Savings	**754**	**1,307**	**7.4%**

Figure 5-4. Total Gasoline and Diesel Savings from Transportation Efficiency Policies in the Medium Case Scenario



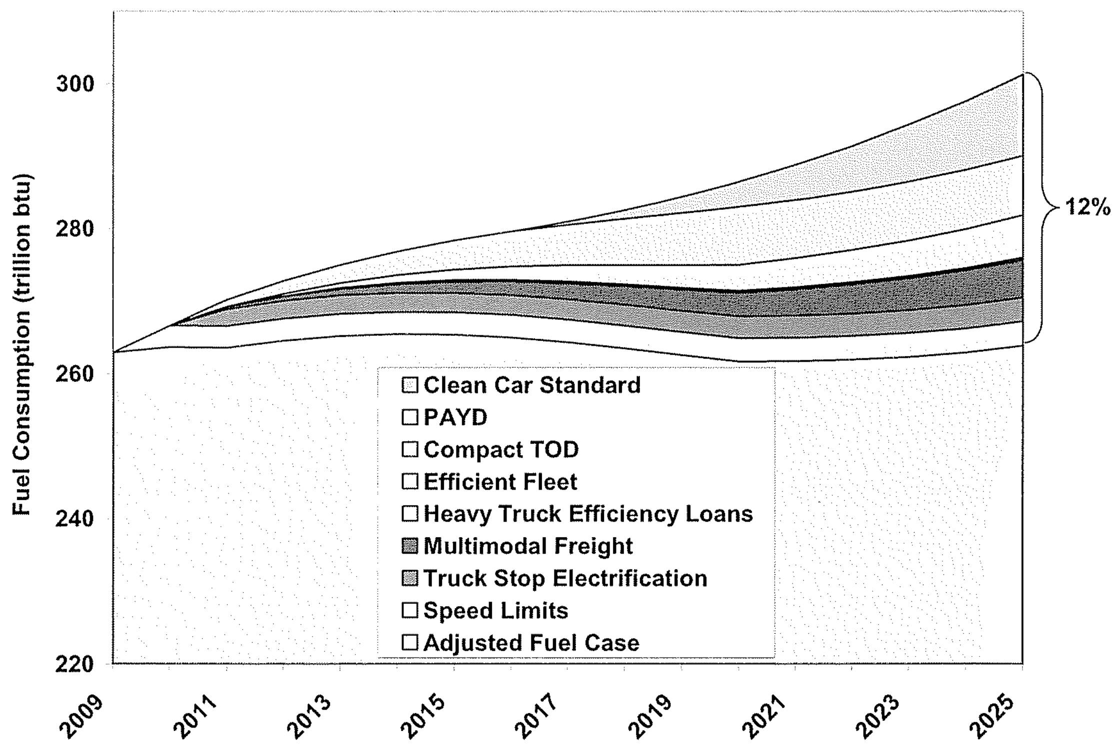
High Case Scenario

The estimated total fuel savings in 2015 and 2025 for the high case scenario are shown by policy/program in Table 5-3. Under this scenario, Arkansas can achieve combined fuel savings of 12% savings from the reference case (see Figure 5-5).

Table 5-3. Summary of Transportation Savings by Policy or Program in the High Case Scenario

	Annual Transportation Savings by Policy (thousand barrels)	2015	2025	Savings in 2025 (%)
1	Clean Car Standard	0	2,130	5.6%
2	Pay-As-You-Drive Insurance	772	1,560	4.1%
3	Transit Expansion / Concentration of Urban Development	120	889	3.0%
4	Light-Duty Speed Limit Enforcement	399	419	1.1%
5	Efficient State Vehicle Fleet	**8**	**9**	**<1%**
	Total Gasoline Savings	**1,299**	**4,998**	**13.8%**
6	Heavy Truck Efficiency Package	37	45	0.3%
7	Truck Stop Electrification	554	680	3.8%
8	Freight Intermodal Investments	260	895	5.1%
9	Heavy-Duty Speed Limit Enforcement	171	196	1.1%
	Total Diesel Savings	**1,044**	**1,908**	**10.0%**

Figure 5-5. Total Gasoline and Diesel Savings from Transportation Efficiency Policies in the High Case Scenario



Discussion of Transportation Efficiency Policies

Clean Car Standard

The energy efficiency of gasoline-fueled automobiles relates directly to their emissions of carbon dioxide, the dominant greenhouse gas (GHG). While states are not permitted to set fuel economy standards, they can adopt greenhouse gas standards for vehicles, and many have done so. To date, 16 states have adopted a clean car standard, first introduced in California, which will reduce greenhouse gas emissions from new vehicles by 30% from 2002 levels by 2016 while cutting emissions of traditional criteria pollutants as well. These states are Arizona, California, Connecticut, the District of Columbia, Florida, Maine, Maryland, Massachusetts, New Jersey, New Mexico, New York, Oregon, Pennsylvania, Rhode Island, Vermont, and Washington.

In May 2009, the Obama Administration issued an order to establish harmonized federal standards for fuel economy and greenhouse gas emissions for model years 2011 to 2016 that will track California's standards in stringency. A joint rulemaking by the EPA and the U.S. Department of Transportation (DOT) was issued on April 1st, 2010 calling for a fleet-wide average fuel economy of 34.1 miles-per-gallon by 2016. Nevertheless, California retains the right to set more stringent standards for the period beginning in 2017 and has committed to doing so as part of the implementation of the state's greenhouse gas reduction program. The California Air Resources Board (CARB) is currently in the process of determining the appropriate level for tailpipe emission standards for this next stage of the clean car standard.

The policy analyzed here is Arkansas' adoption of the clean car standard. The harmonization of federal and California standards means this action will have no impact on vehicle efficiency before 2017. Under both scenarios, we assume that Arkansas, along with other states adopting the clean car standard, would require new vehicles on average to achieve greenhouse gas emissions equivalent (for gasoline vehicles) to 60 miles per gallon by 2025.

However, modeling the impact of a 60 mpg target in 2025 using current fuel economy levels as a baseline overstates the potential savings from the implementation of such a policy given that the U.S. EPA and DOT have already announced plans for even more stringent targets between 2017 and 2025. Therefore, we created an alternate reference case for the analysis of the Clean Car Standard policy option that acknowledges the vast improvements in fuel economy that will be achieved during the next round of rulemaking. EPA and DOT propose 2025 standards that range from 190 g/mi (equivalent to 43.4 mpg) to 143 g/mi (equivalent to 56.2 mpg) (Federal Register 2010). We use the mid-point of this range (49.8 mpg) to evaluate vehicle stock impacts and create alternate fuel economy and gasoline consumption reference case projections.

The primary pathway to meeting these standards in the earlier years will be accelerated penetration of technologies already available, such as variable valve timing, direct injection, turbocharging, more efficient transmissions, and perhaps diesel engines. In the later years, greater use of lightweight materials, hybrid-electric vehicles, and plug-in electric vehicles is likely.

Gasoline savings from the clean car standard will be zero in 2015 (relative to the Reference Case) but will reach 2.1 million barrels in 2025 under both scenarios, amounting to almost 6% of total gasoline consumption in 2025.

If the prospect of a clean car standard is unappealing as an efficiency policy, Arkansas may want to consider the implementation of a feebate. A feebate is a market-based approach to promoting vehicle efficiency, in which a consumer is subject to a fee or granted a rebate upon purchase of a vehicle, depending on the vehicle's fuel economy. Part of the rationale for a feebate is that consumers tend to undervalue fuel economy when they are choosing a vehicle. A feebate can be designed to be "revenue-neutral," so that the implementing entity incurs no net cost or revenue. Another positive feature of feebates is that they provide an incentive for greater fuel efficiency in vehicles of any efficiency level and continue to do so as long as the program remains in place.

Pay-As-You-Drive Insurance

One reason that people use their vehicles as much as they do is that a high percentage of vehicle-related costs are "fixed," i.e., independent of the number of miles the vehicle is driven. The impacts of vehicles, however, are very dependent on how much people drive. One approach to reducing miles driven is to convert fixed costs to variable costs. This can be accomplished in part by Pay-As-You-Drive (PAYD) insurance.

PAYD insurance ties the rate paid by an individual to the number of miles driven over a fixed period of time. Drivers would pay a portion of their premiums up front, and the remainder would be charged in proportion to mileage, as determined by a global positioning device or periodic odometer readings. Converting fixed insurance costs to variable costs through PAYD insurance could reduce vehicle use by as much as 8% given varying insurance rates (Bordoff & Noel 2008). A PAYD program could be an insurance company policy or product, but in Arkansas some action on the part of the state may be required to remove regulatory obstacles to changing the basis for premiums or to promote the program (Guensler 2003).

The policy proposed here is to phase in PAYD insurance in Arkansas, starting with a pilot program. For three years beginning in 2010, the state would offer incentives for insurance companies to offer policies based largely on miles driven. More specifically, the state would grant $200 to insurance agencies for each one-year policy they write for which 80% or more of the pre-program policy cost is scaled by the ratio of miles driven to the state or regional average miles driven. The incentive is necessary so long as PAYD is optional; without it, insurance companies may be concerned about losing revenues from the low-mileage customers who would choose such a policy without being able to offset these costs with higher premiums for high-mileage customers. Assuming the pilot program is successful, mandatory PAYD insurance would be phased in over the next ten years.

Like other pricing policies designed to reduce miles driven and promote alternative travel modes, PAYD insurance may raise questions of equity, especially in rural areas, where alternatives to driving are not readily available. This is especially true in a state like Arkansas that is predominantly rural and where agriculture plays such an important role in the economy. Insurance premiums are generally lower in rural areas than in urban areas, however, so high-mileage premiums would be smaller there. Moreover, a PAYD program could be designed to compare a rural driver's annual mileage to that of other rural drivers for purposes of determining the insurance premium. Or the program could be crafted so it is limited to drivers with automobiles registered in metropolitan statistical areas as defined by the U.S. Census, thereby eliminating the equity issue between rural and urban drivers altogether. Also, low-income drivers generally drive less than higher-income drivers, and low-income drivers as a group consequently would be net beneficiaries of pay-as-you-drive insurance programs (Bordoff & Noel 2008).

Nonetheless, given potential objections to PAYD in rural areas, we assume for the medium case that PAYD is required only in the 12 high-growth counties outlined in Figure 5-3. In the medium case, PAYD is projected to save 432,000 barrels of gasoline in 2015 and 920,000 barrels in 2025. In the high case, we assume that PAYD insurance would be mandatory across the state, saving 772,000 barrels and 1.6 million barrels in 2015 and 2025, respectively.

To maximize the benefits of PAYD insurance, drivers must have access to alternative modes of transportation. Title 26 of the Arkansas Code (Title 26-73-111) allows local jurisdictions to implement a local option sales tax for the purposes of funding public mass transit, though the ordinance must be voted on by constituents in the jurisdiction. A local option sales tax for the benefit of public transit gives jurisdictions with existing transit systems a leg up on financing for expansion and improvement. In addition to the tax revenues, counties opting in would have access to matching funds for transit from the state.

PAYD insurance is one of many pricing policies that could be adopted to reduce vehicle miles traveled. Others include fees to enter metropolitan areas, parking pricing, congestion pricing, and vehicle miles traveled fees. PAYD insurance is used here to exemplify the importance of pricing strategies in a comprehensive approach to transportation system efficiency.

Compact, Transit-Oriented Development

The increasing congestion in Arkansas' metropolitan areas caused by population growth, economic development, and greater interstate travel across the region portends the growing inadequacy of the current roadway system to accommodate burgeoning demand. Compounded by higher fuel prices and economic uncertainty, these trends are causing many to question the wisdom of current development patterns and leading Arkansans to request more variety in their travel options. But in a state with limited public transit and the 12th largest roadway system in the nation, there is much to be done to make its transportation sector more efficient.

Managing growth in vehicle miles traveled is a critical component of achieving maximum energy efficiency potential. Yet Arkansas' VMT is expected to grow considerably by 2025: in the Little Rock–North Little Rock metropolitan statistical area (MSA), VMT is expected to grow by 40%; in the Fayetteville–Springdale–Rogers MSA, VMT is expected to grow by 65%; and VMT in the state as a whole is expected to grow by about 36% (AHTD 2009).

Integrating transportation and land use planning, along with the provision of viable alternatives to the automobile for certain trips, is essential to reducing the growth in driving and transportation energy use. Yet in Arkansas as in other states, zoning and regulation of land use is a function of local government, which has a limited role in developing transportation infrastructure and scenarios. Transportation planning falls under the jurisdiction of the Arkansas State Highway and Transportation Department (AHTD) and the state's eight Metropolitan Planning Organizations (MPOs). These entities will need to greatly increase their coordination to moderate VMT growth.

Nationally, the demand for transit-oriented development is growing rapidly. By 2025, an estimated 14.6 million households will be looking to rent or buy homes near transit stops (Reconnecting America 2008a). In Arkansas, almost three-quarters of the population growth projected to occur by 2025 will occur in the Little Rock–North Little Rock MSA and the Fayetteville–Springdale–Rogers MSA. However, in these high-growth regions there are limited transportation choices for citizens outside of their personal vehicles. On the other hand, recent and future growth trends have catalyzed most metropolitan areas to develop long-range transportation plans that incorporate rail transit services as well as expanded bus routes and bicycle/pedestrian pathways. Little Rock, for example, completed the first phase of its River Rail Vintage Streetcar project in 2004, but the route is limited to 2.5 miles and eleven stops. While some infrastructure exists upon which to expand the state's mass transit systems, concerns over cost, population density, and access to right-of-ways have hindered any major investments.

Transit-oriented development provides several non-energy benefits that are important to consider. It can boost the economic productivity of communities by attracting a number of new and varied businesses to the area. Compact development also helps to reduce infrastructure costs beyond road and highway maintenance: denser urban areas require less investment in water- and energy-related infrastructure, an issue that is of particular concern in the Northwest Arkansas region. Additionally, transit expansion and the subsequent reduction in vehicle miles traveled and gasoline consumption translate to less money being shipped outside of the local economy to pay for fuel resources and increased job creation within the state, particularly in industries responsible for the physical construction of new rail lines and multi-family housing (Reconnecting America 2008b).

In this analysis, we represent an aggressive policy package achieving compact, transit-oriented development through the assumption that one-half (50%) of all population growth in six counties in two metropolitan areas occurs within a half-mile of existing and future transit stops. Extensive transit expansion is also assumed in all six areas. These conditions would result in substantial VMT and gasoline savings, due both to the proximity of transit for these new residents and to the increased density of the areas in which the population growth is concentrated.

This concentration of growth would strongly support elements of development plans adopted or proposed by some of Arkansas' metropolitan regions. For example, according to Metroplan, the designated MPO for central Arkansas, in 2009 new residential construction permits for multi-family buildings outpaced those for single family in the Little Rock area for the first time in several years: 57.5% versus 42.5%, respectively (Metroplan 2009b). The Northwest Arkansas region has also been experiencing a rise in multifamily building construction. According to the Northwest Arkansas Regional Planning Commission (NWARPC), the number of multifamily housing unit construction permits in the region more than doubled between 2007 and 2008, while the number of single-family housing unit construction permits in the region declined by almost 50% (NWARPC 2008).

Methodology

Our analysis for this policy considers two proposed transit plans for the Little Rock and Northwest Arkansas regions. The Transit Vision Plan created for the Central Arkansas Regional Transportation (CART) system (Metroplan 2009a) and the proposed light rail transit system for Northwest Arkansas (City of Fayetteville 2006) are taken as the model transit systems that we reference to analyze the potential savings from investment in transit-oriented development. Although we have only modeled savings from development around light rail systems, both regions have developed plans that also include regional commuter rail, expanded bus service and bus rapid transit, and pedestrian/bicycle pathways.

Metroplan has envisioned for the CART system the development of three light rail routes servicing downtown Little Rock and the surrounding region that would require service stops no more than every half-mile and no less than every two miles along each route:

- Northeast Corridor: US 67 from Little Rock to Jacksonville, ~18 miles
- West Corridor: I-630/Chenal/Kanis from Downtown to Ferndale Cutoff, ~8 miles
- Southwest Corridor: Rock Island from Downtown to Benton, ~25 miles

Additionally, the City of Fayetteville's City Plan 2025 proposed a light rail transit system connecting the four major cities in the region—Fayetteville, Springdale, Rogers, and Bentonville—with a 50–60 mile route comprising 10 stops (City of Fayetteville 2006).

According to Metro 2030.2, the three light rail lines of the proposed CART system would extend about 50 miles. Our medium and high case scenarios are differentiated by the number of proposed stops, which, given the requirements above, would range between 25 (maximum of two miles between stops) and 100 (minimum of a half-mile between stops). The incorporation of the Northwest light rail transit system would add an additional 10 stops to the analysis, which we keep static across scenarios.

According to a recent National Academy of Sciences study, research to date indicates that doubling density in urban areas reduces residents' VMT by 5–12% and, if coupled with complementary policies such as improved public transportation, by as much as 25% (TRB 2009). We assume a 15% drop in VMT near a transit stop for each doubling of density in the medium case, and a 25% drop in the high case. For this policy, only those living within a half-mile of transit are assumed to reduce fuel consumption. As a result, fuel savings represent only a modest percentage of statewide gasoline consumption by 2025. Continuing this concentration of growth in areas that provide alternatives to driving and enhanced accessibility to jobs, shopping, and other common destinations, however, would result in a major reduction in VMT in the long term.

Gasoline savings from the reduced VMT due to compact, transit-oriented growth as described above in the medium case reach 189,000 barrels in 2015 and rises to 813,000 barrels by 2025. In the high case, which assumes a greater VMT reduction with increased density, savings would reach 274,000 barrels in 2015 and 1.1 million barrels in 2025.

Potential Hurdles Facing Transit-Oriented Development

To support the growth of transit-oriented communities, state and municipal governments can introduce a variety of supplemental policies. Across much of the country, some of the greatest barriers to more compact, transit-oriented developments are local zoning regulations (TRB 2009). Traditional zoning practices in the United States have historically been derived from the need to prevent overcrowding in urban centers but have resulted in the patterns of sprawl development immediately outside urban centers across the country. States can play an important role in providing incentives to local governments that encourage the appropriate use of higher-density zoning, effectively meeting the growing demand for and allowing for the creation of transit-oriented development (TOD) communities to reduce statewide VMT. Massachusetts, for instance, adopted the Smart Growth Zoning Overlay District Act in 2004, under which municipalities can propose new high density zoning provisions for consideration to the state. Areas that will implement this up-zoning must be located near transit stations and provide a certain percentage of affordable housing. If the zoning is approved, the municipality receives an initial payment from the Commonwealth Trust, plus additional funding for each unit built in the rezoned district (EOHED 2010).

Another existing barrier to compact, transit-oriented development is the perpetuation of parking subsidies for urban centers. Nationally, parking subsidies are estimated to amount to between $125 billion and $375 billion annually and lead to increased VMT as commuters are encouraged to drive more (Shoup 2005). Removing these subsidies will encourage commuters to use more energy-efficient travel alternatives and will, in effect, incentivize the creation of compact, transit-oriented communities around primary urban centers in Arkansas.

Potential and Existing Policies in Arkansas to Promote Transit-Oriented Development

Additional policies to facilitate the creation of and movement to high-density communities could include location efficient mortgages in these districts as well as integrated street design to improve street connectivity and allow easy access to commercial areas.

In 2005, the state legislature passed Act 2275, the Regional Mobility Authority Act (revised in 2007 as Act 389) in order to "provide for the improvement of surface transportation systems in the state of Arkansas by authorizing the creation of regional mobility authorities [...]." The act empowers counties, on their own or collectively, to create a regional mobility authority (RMA), which is essentially a regional government agency, that may levy taxes, issue bonds, enter into contracts, and implement a variety of other mechanisms intended to augment existing transportation systems, which includes any kind of surface transportation system. Funding generated by RMAs is not intended to supplant state or federal transportation funds, but rather to supplement those funds. The law requires all proposed funding mechanisms to be approved by voters, which in turn requires RMAs to engage and educate their citizens about the costs and benefits of expanded public transportation systems.

Only one RMA has been established in Arkansas since the legislation was passed: the Northwest Arkansas Regional Mobility Authority, which includes Washington and Benton counties and an additional fourteen cities in the region. Establishing an RMA is an extremely useful tool that aids in the completion of transit projects, especially if other sources of funding prove to be inadequate. By bringing together representatives from a number of jurisdictions within a region whose economies and transportation systems are interdependent, establishing an RMA is invaluable to coordinating what could otherwise be a fragmented and inefficient response by individual jurisdictions to growing demand for public transit.

Heavy Truck Efficiency Package

In 2009, diesel fuel consumption accounted for 29% of all transportation fuel use in Arkansas; the majority of this was consumed by heavy trucks (EIA 2010c, ACEEE analysis). Tractor-trailers in turn dominate heavy truck fuel usage, due to their high annual mileage and relatively low fuel economy. Trucking companies are sensitive to fuel costs, which are typically second only to labor among their business expenses; a tractor-trailer may consume well in excess of $50,000 of fuel annually. Truck manufacturers may therefore be more aggressive in improving the fuel economy of their products than are light-duty vehicle manufacturers. Yet substantial barriers to fuel efficiency do exist in the truck market, including the rapid turnover of trucks from first to second owner and the lack of standardized information on truck fuel economy.[41] Consequently, there are numerous technologies and strategies available to improve fuel economy that are not fully utilized. Indeed, average fuel economy for new tractor-trailers could be raised by over 50% through a variety of cost-effective existing technologies, including aerodynamics of tractor and trailer, engine improvements, low rolling resistance tires, transmission enhancements, and weight reduction (NESCCAF 2009).

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[41] Fuel economy standards do not currently exist for heavy trucks but are being formulated pursuant to the 2007 Energy Independence and Security Act (EISA).

The heavy truck efficiency policy analyzed here would establish a low-interest loan program, beginning in 2010, to promote the purchase of new tractor-trailers or the retrofit of existing tractor-trailers with approved energy efficiency technologies and equipment. In particular, equipment in the efficiency package identified by U.S. EPA's SmartWay Transport Partnership would be eligible for loans to truck owners in Arkansas. This SmartWay upgrade kit, which includes aerodynamic add-ons for trailers, efficient tires, and auxiliary power units (APUs) allowing medium- and long-distance truckers to eliminate overnight idling, has been found to reduce fuel consumption by 15% or more while reducing most emissions. The federal government's adoption of fuel economy standards for heavy trucks will likely result in universal adoption of technologies in the SmartWay package among new trucks, reducing the efficacy of the loan program in the latter part of the analysis period. However, because federal standards are still uncertain, we have modeled fuel savings in the absence of such standards. The loan program should in that case be adjusted to incentivize early adoption of technologies not needed to achieve the federal standards.

The medium case scenario assumes incentives are put in place for the adoption of this standard package of improvements, while the high case assumes a mandate. Such a mandate has been adopted in California and will apply not only to fleets registered in California but also to those operating there. We did not have the data on out-of-state trucks necessary to evaluate this broader requirement, but savings in this case would clearly be far larger.

We estimate the low-interest loan program to yield diesel savings of 29,000 barrels (a 0.19% reduction) by 2015 and 35,000 (0.20%) by 2025 under the medium case scenario. Under the high case, savings rise to 37,000 barrels (0.24%) in 2015 and 45,000 barrels (0.26%) in 2025. These reductions in fuel use save $5.2 million in the medium case and $6.7 million in the high case by 2025. The savings are relatively modest due to the surprisingly low number of trucks registered in Arkansas that travel long distances on trips originating in the state.[42]

Truck Stop Electrification

Another opportunity to save diesel fuel is by reducing idling of long-haul trucks that pass through Arkansas but are registered elsewhere. Long-haul tractor-trailers typically idle several hours per day to produce heating, cooling, and power for drivers when their vehicles are parked. Various devices are available or under development to eliminate the need for extended idling, including direct-fired heaters, auxiliary power units, and truck stop electrification (TSE). None is currently widely used in the U.S.

The Truck Stop Electrification policy would establish a low-interest loan program to promote electrification of parking spaces at truck stops and rest areas in Arkansas, allowing drivers to turn off their truck engines when stopped for extended periods. TSE can use either on-board or off-board systems. An on-board system simply provides power outlets for trucks that have electrical heating/ventilation/air conditioning (HVAC) systems and an electrical plug, while an off-board system brings HVAC to the truck, requiring no special equipment on the truck itself. For this discussion, we assume off-board systems will be used, since this would place no requirements on the out-of-state trucks that are the primary users of truck stops. On-board systems would be far less expensive to truck stop owners, however, and the number of trucks manufactured with electric HVAC systems will likely increase, so the best strategy might be a mixture of the two system types.

For this policy, the medium and high case scenarios are the same. Assuming that all spaces in all of Arkansas' truck stops and rest areas are electrified by 2020, we estimate that diesel savings will reach

[42] Data were taken from the 2002 Vehicle Inventory and Use Survey (VIUS), which estimated that Arkansas had only 1,000 heavy trucks with a range of 200–500+ miles per trip in 2002. By comparison, North Carolina has 15,300 such trucks. Considering that freight-intensive businesses like J.B. Hunt and Wal-Mart call Arkansas home, it seems likely that these fleets are registered elsewhere and are, therefore, not captured by our Arkansas-specific analysis.

554,000 barrels (a 3.6% reduction) in 2015 and 680,000 barrels (3.8%) in 2025, which corresponds to $101 million in fuel cost savings by 2025.

Intermodal Freight Investment

On a tonnage basis, 69% of Arkansas' freight is transported by truck, 18% by rail, 6% by water, and 1% by air. Trucking dominates partly because the state serves as a major throughway for freight shipments traveling east-to-west on Interstate 40 and north-to-south on Interstates 30 and 55. Yet the U.S. Department of Transportation estimates that, due to increased congestion, most segments of I-30 and I-40 in Arkansas will be operating at a Level of Service D or worse by 2020 (AHTD 2007). This has implications for both freight trucking and drivers of light vehicles, both in terms of time lost and in the costs associated with increased fuel use.

A concerted effort to pursue the opportunities available to improve the intermodal freight network in Arkansas could bring substantial economic development benefits and energy savings through greater reliance on modes less energy intensive than trucks. Achieving the full benefit of a modally-diverse system of goods movement would require actions like expanding rail and marine infrastructure, guiding the locations of industrial facilities, and adjusting the tax code, and would need to be integrated into development strategies at every level of government.

The Intermodal Freight Investment policy proposes, in the high case, to divert 10% of long-distance truck miles in Arkansas to rail and another 5% to waterborne transport, phased in by 2025, under a $300 million infrastructure investment.[43] A 10% truck-to-rail diversion is in general terms an objective that has been cited in various contexts as consistent with the potential to increase rail's share of total U.S. freight without dramatic changes in our goods movement system; we model this level of mode diversion in the High Case. We found no similar rule of thumb for the potential of truck-to-barge diversion, but we model a 3% diversion in the High Case as an aspirational target to demonstrate potential savings. In the medium case, we model a 7% truck-to-rail diversion and a 2% truck-to-marine diversion.

There is clear potential for expanded intermodal activity in Arkansas. Along the Detroit-to-Mexico Freight Corridor, which passes through Arkansas along Interstates 30, 40, and 55 and the parallel rail corridors, intermodal services currently capture barely more than 0% of freight tonnage (AASHTO 2002). The Arkansas State Rail Plan (AHTD 2002) also cites lack of access to rail freight transportation for state industries as one of the top five issues facing the rail system. Likewise, the Arkansas State Public Riverport Study and Needs Assessment (AHTD 2005) found that 70% of port officials responding to their survey saw the lack of truck/rail/barge intermodal services as a major impediment to business operations and growth.

Description of State Freight Resources

Arkansas has 1893 miles of Class I rail, which account for 69% of total track mileage in the state. These lines provide the vast majority of freight services in the state by making long-haul deliveries to national markets and freight exchanges at international ports. Class I mileage in Arkansas is split between Union Pacific (UP), Kansas City Southern (KCS), and Burlington Northern and Santa Fe (BNSF), which account for 77, 12, and 11% of track mileage, respectively. There are currently three intermodal rail/truck yards operated by Class I railroads in the state: at Ebony (UP) and Harvard (BNSF) in Crittenden County, and in North Little Rock (UP) (AHTD 2002).

[43] This is based on estimated investment needs of $95 million for port operations (AHTD 2005), $130 million for Class III rail operations (AHTD 2002), and the proposed $112 million cost of a new Norfolk Southern intermodal facility to be opened in Memphis, TN in 2012 (Norfolk Southern 2010). These proposals to do not assume a 10% diversion; rather, that is an assumption made based on experience elsewhere.

Class III, or shortline, railroads make up a small share of freight track mileage in the state (857 miles) and provide switching service and railcar spotting for their respective industries, as well as feeder service to the Class I railroads. Some Class III railroads also provide limited intermodal service, but capacity expansion is hindered by lack of adequate equipment to transfer freight to other modes and few locations (AHTD 2002). This latter barrier may have been exacerbated by Class I railroads seeking economies of scale by consolidating smaller satellite intermodal terminals and sending freight through a few large hubs. This, in turn, may have increased the circuitousness of intermodal shipments, trucking costs, and fuel use (Ozment 2001).

Arkansas' state waterway system is large but underutilized. Nine public ports and harbors on 1,000 miles of navigable waterways handled 1.3 million tons of freight in 2004, but poor access to roadways and railroads, inadequate intermodal transportation capabilities, and deteriorating infrastructure limit the full utilization of freight capacity in the future (AHTD 2005).

Heavily-traveled interstates such as I-30, I-40, and I-55 carry large volumes of long-distance truck trips that could in principle be partially served by intermodal rail and marine. Other types of rail services, such as shuttles serving inland ports or trailers on flatcar, could provide relief to key highway links as well. Landside facilities such as logistics hubs and intermodal terminals are also essential to greater use of rail and marine intermodal services.

Potential Investments

Fully specifying the policies and projects necessary to achieve the assumed mode shift is beyond the scope of our analysis, but we include this element to show the magnitude of savings that might be expected to follow from a strong intermodal freight program. A key ingredient of a policy to bring about such a shift would be state investments in individual infrastructure projects that have already been presented and well-received in forums seeking to rationalize the transportation system in Arkansas.

The conditions for the expansion of intermodal freight in Arkansas already exist. State Act 690, originally established as an economic development tool, gives authority to contiguous municipalities and counties to construct and equip regional intermodal facilities, and to use any available revenues, including bonds, to fund such projects (State of Arkansas 1997). Currently, seven such regional authorities exist in Arkansas, and there are ongoing investments in infrastructure improvements there, funded by both state earmarks and federal funds (McKinney 2010).

At least half of these authorities, however, are still in the approval or fund-raising stages. Recent renewed interest in establishing intermodal authorities appears to stem from the potential economic development benefits of the proposed facilities, especially job creation. Four important examples of potential near- to mid-term intermodal freight investments are:

- The River Valley Intermodal Facilities Authority, which is moving forward with a proposed new intermodal facility in Pope County. The facility recently completed its environmental impact review. It will occupy approximately 800 acres along the Arkansas River, and will include the capability for transfers among truck, rail, and barge (FHA 2010).
- The Western Arkansas Regional Intermodal Transit Authority located in Crawford and Sebastien Counties, which announced its formation in August 2009. The authority was approved for $375,000 in seed funding from the Arkansas General Improvement Fund (The City Wire 2009). Similar authorities in the southwest and northeast regions of the state announced their formation in the summers of 2010 and 2009, respectively (Arkadelphia Alliance 2010; The Times Dispatch Online 2009).
- The Southeast Arkansas Regional Intermodal Authority, which was the first authority to be set up under Act 690, is a major hub for trade with Latin America through the Ports of New Orleans and Houston, and is projected to reach 150,000 outbound lifts and two million tons of outbound freight by 2021 (TransSystems 2001).

- The Little Rock Port Complex. A study by the Arkansas State Highway and Transportation Department suggested that the complex is well-positioned geographically to take advantage of opportunities for mode shift from truck to rail (both container-on-flatcar and trailer-on-flatcar) and waterborne modes, especially for primary metal, fabricated metal, and chemical products (AHTD 2006).

Support for intermodal freight also exists within the trucking industry in Arkansas. In August of this year, USA Truck and BNSF announced a partnership to move 53' domestic containers on the rail network (JOC 2010). In addition, the President of the Arkansas Trucking Association has indicated that the organization supports more intermodal transportation in the state, and would even be willing to help pay for it (Kidd 2010).

A concerted effort to follow through on the freight strategies recommended would substantially decrease fuel use and deliver corresponding cost savings. This is because, on a ton-mile per gallon basis, rail and marine use only 38% and 27%, respectively, of the fuel used by trucks (MARAD 2007).

In the medium case, diverting 7% of truck freight to rail and 2% to barge would save 180,000 barrels by 2015 (a 1.2% in statewide diesel consumption) and approximately 619,000 barrels by 2025 (a 3.5% reduction). This amounts to $92 million in fuel savings by 2025.

Under the high case, we assume that Arkansas achieves a 13% diversion of long-haul truck freight to rail and barge, saving approximately 260,000 barrels of diesel in 2015 (a 1.7% reduction) and 895,000 barrels in 2025 (a 5.1% reduction). Fuel cost savings would amount to $133 million in 2025.

Efficient State Vehicle Fleet

Reducing petroleum use state vehicle fleets promotes energy independence and cleaner air. Lower fuel consumption means not only lower emissions of greenhouse gas and other criteria pollutants, but also cost savings. And many states currently face difficult fiscal circumstances, making low-cost and high-return steps to reduce petroleum use in the state vehicle fleet even more attractive.

Several states have established programs to improve the environmental performance of their fleets and reduce fuel costs by purchasing the most efficient, clean vehicles possible. Maine requires that replacement sedans have highway fuel economy of at least 30 miles per gallon; hybrids are to be purchased whenever cost-effective. In California, fleet vehicles must meet the ULEV tailpipe emissions standard, and the legislature has requested an analysis of the costs and benefits associated with reducing fleet energy consumption by 10%. Minnesota and Washington have defined special categories of "High MPG" vehicles in state bid specifications, to allow purchase of efficient vehicles that might not otherwise appear in state vehicle contracts. In Missouri, the State Fleet Efficiency and Alternative Fuel Program requires that all vehicles purchased meet or exceed the federal Corporate Average Fuel Economy standards.

Some fleets are raising fuel economy by ensuring that large vehicles are only purchased when necessary. Even then, fuel consumption can be further improved by purchasing the most efficient among all functionally equivalent vehicles.

State Vehicle Procurement in Arkansas

Arkansas' state agencies must submit applications for new vehicle purchases with the Arkansas Department of Finance and Administration (DFA). In addition to state guidelines/prerequisites codified in R1-22-8-209, vehicle purchases must meet a number of federal and state requirements:

- The Energy Policy Act of 1992 (EPAct) requires a certain percentage of state fleet vehicles (75% of "covered" vehicles) to be alternative fuel vehicles, consuming petroleum/ethanol blends or biodiesel.

- A.C.A. 19-11-217 (c) (2) (A) requires the development and implementation of a plan for all state agencies to acquire vehicles that will reduce the overall annual petroleum consumption of those state agencies by at least 10% by January 1, 2009. Additionally, the State Procurement Director is required to report annually on the progress of the plan toward achieving the goal.
- R1-22-8-205 (5) (c) & (d) authorizes the Director of the DFA to review agency applications and make changes where "deemed necessary."

ACEEE reviewed a variety of materials to ascertain the degree to which Arkansas has been meeting its obligations regarding vehicle procurement, including the state's vehicle database and supporting documents for the reporting requirements mandated by A.C.A. 19-11-217 (c) (2) (B) (i). From this review, we determined that: 1) Arkansas could be doing more to meet its federal and state statutory requirements; and 2) vehicle procurement relies heavily on least-cost analysis with a simple payback that does not take into account other factors, despite the emphasis placed on such evaluation as further delineated in R1-22-8-209.[44] A more concerted effort to meet its obligations and less reliance on seemingly subjective agency application reviews would yield significant fuel cost savings for the state.

For example, out of the state's almost 8,600 vehicles, alternative fuel vehicles, including hybrids, comprise only about 4%. Regardless that this falls far short of its EPAct obligation, ACEEE did not come across any materials that document how frequently, if at all, alternative fuel vehicles are actually filling up with alternative fuels.

In terms of the fuel savings target promulgated by A.C.A. 19-11-217 (c) (2) (A), ACEEE was unable to acquire reports documenting whether or not state was able to meet the 10% fuel savings goal by January 1, 2009. We are uncertain if the reports were actually finalized, but we strongly recommend that future efforts to meet fuel savings targets are well-documented and transparent.

Finally, Arkansas' utilization of a least-cost analysis as a primary basis for vehicle procurement decisions should be modified to ensure that decisions are based on full-life costs, rather than solely on purchase price. A procurement policy focusing on best-in-class, not including hybrids, would reduce maintenance costs and increase vehicle resale values, along with ensuring greater fleet fuel efficiency, reducing the overall full-life costs. The incremental costs of non-hybrid, best-in-class purchases are also lower than those of hybrid purchases, increasing the cost-effectiveness of such a policy.[45] Nonetheless, there is evidence that existing hybrids have a higher resale value and lower maintenance and repair costs than comparable vehicles, giving hybrids a lower full-life cost (see Kelley Blue Book, Edmunds.com).

Our estimate of petroleum savings in our medium case is based on a policy of purchasing the best-in-class among functionally equivalent vehicles. The purchase of hybrids is not considered in this scenario. We estimated this procurement policy would generate cumulative fuel savings of 4.7 million gallons, or 112,000 barrels, through 2025.[46] Our high case also assumes a procurement policy of best-in-class; however, we also assume a hybrid purchase requirement of 10% and a cross-class substitution (supplanting light-duty vehicle purchases with additional purchases of cars/sedans) of 33%. Under these assumptions, we estimated that our high case would generate fuel savings of 5.1 million gallons, or 121,000 barrels, through 2025. Assuming fuel costs of $2.45 per gallon (which does not include the state fuel tax),[47] we estimate fuel cost savings of $10.3 million and $13.3 million through 2025 in our medium and high scenarios, respectively.

[44] R1-22-8-209 "Replacement of Existing Vehicles" provides eligibility criteria for vehicle replacement, including miles traveled, age, and repair cost.
[45] There is no consistent pattern in the cost of these efficient vehicles relative to the cost of the average vehicle in the class, and we assume that, on average, the purchase of best-in-class vehicles has no impact on the purchase cost.
[46] There are 42 gallons in a barrel of gasoline.
[47] We assume a price of $2.67 per gallon as reported in the DFA's cost comparison spreadsheet for January 2010. Arkansas' state gasoline tax is 21.5 cents per gallon (¢/gal).

Speed Limit Enforcement

At high speeds, vehicle efficiency falls off rapidly with further increases in speed, as aerodynamic drag begins to dominate vehicle energy requirements. The speed at which fuel economy is highest varies from vehicle to vehicle, but is typically below 60 miles per hour for a light-duty vehicle (DOE 2010). Federal Highway Administration tests of nine light-duty vehicles in 1997 found that fuel economy declined on average by 3.1% when speed increased from 55 mph to 60 mph and by 8.2% increasing from 65 to 70 mph (Davis, Diegel & Boundy 2006). For a heavy truck such as a tractor trailer, fuel economy declines by about 2% per mph at highway speeds (Goodyear Tires 2010). Thus, slowing high-speed driving is one means of improving the real-world efficiencies of cars and trucks. This could be accomplished by more stringently enforcing the existing speed limits.

Speed limits in Arkansas are currently restricted to 30 mph in urban areas and 60 mph on both rural and urban highways (NHTSA 2010). No recent bills have been introduced to address reducing statewide speed limits.

Rather than lowering current speed limits, the policy considered here targets a more stringent enforcement of the existing highway speed limits. Doing so could both increase highway safety and provide fuel savings. Given demands on the time of police and highway patrol, additional enforcement might best be approached through increased use of radar, lasers and speed cameras, and education.

In Arkansas, 60% of all driving is on highways (AHTD 2008). This leads to an estimate of energy savings of up to 2.4% from improved enforcement of speed limits by 2025 under both the medium and high case scenarios.

Box 1. Light-Duty Vehicle Electrification in Arkansas

Plug-in hybrid electric vehicles (PHEVs) and all-electric vehicles (EVs) are now available in the United States and several new models will enter the market in the next few years. As part of his campaign, President Obama announced his goal to have one million PHEVs on the road by 2015. With the amount of national interest in electric vehicles building steadily, Arkansas may choose to actively pursue this growth industry, on both production and purchase ends

A range of incentive programs are available to encourage the purchase of electric vehicles and to attract EV component manufacturers to the region. Tax credits are often the easiest way to incentivize the purchase of electric vehicles. Several states such as South Carolina, Louisiana, and others on the East Coast have implemented a tax credit policy that reduces the up-front cost of an alternative fuel or hybrid electric vehicle (HEV). In most cases, electric vehicles are covered under tax credits for alternative fuel vehicles (AFVs).

For Arkansas to effectively promote electric vehicles, a suite of policies will be needed to attract battery researchers and manufacturers to the state, deploy battery technology, and encourage the purchase of EVs. If successful, ACEEE estimates that by 2015 and 2025, the population of electric vehicles could be as highlighted in Table B1-1 below under the medium and high scenarios.

Table B1-1. Electric Vehicle Populations in Arkansas under Medium and High Scenarios

	2015	**2025**
Medium	4,567	76,009
High	16,443	475,053

Gasoline savings that result from the above penetration scenarios could amount to 12,000 barrels in 2015 and 173,000 barrels in 2025. Under the high scenario, savings in 2015 and 2025 would reach 33,000 barrels and 826,000 barrels, respectively.

Chapter Six: Combined Macroeconomic and Emissions Impacts from Electricity, Natural Gas, and Transportation Efficiency

Up to this point in the analysis we have examined the potential costs and benefits of implementing policies that might stimulate greater levels of energy efficiency and onsite solar energy in Arkansas. The evidence suggests that smart policies and programs can drive more productive investments in energy efficiency technologies, and they can do so in ways that reduce the state's total energy bill. But the question remains, what does this mean for the state economy? Do the higher gains in energy productivity—that is, do the increased levels of efficiency investment with their concomitant reduction in the need for conventional energy resources—create a net economic boost for Arkansas? Or, does the diversion of revenues away from energy-related industries negatively impact the economy? In this chapter, we explore those issues and we present the analytical results of an economic model used to evaluate the impact of efficiency investments on jobs, income, and the overall size of the economy.

A recent meta-review of some past 48 energy policy studies done within the United States suggests that if investments in more efficient technologies are cost-effective, the impacts on the economy should be small but net positive (Laitner and McKinney 2008). As shown elsewhere in the report, from a total resource cost perspective, the benefits (i.e., the energy bill savings) outweigh both the policy costs and investments by a factor of two. In other words, the energy efficiency policy recommendations highlighted in the policy scenario result in a substantial savings for households and businesses compared to the costs of implementing the policies. As we also discuss below, this consumer energy bill savings can drive a significant increase in the number of net new jobs within Arkansas.[48] In fact, continued investments in energy efficiency resources would maintain the energy resource benefits for many years into the future, well beyond the period of analysis examined in this report.[49] The state therefore has the opportunity to transition its economy to a more sustainable pattern of energy production and consumption in ways that benefit consumers and businesses.

The results in Table 6-1 below detail the benefits that will accrue to the state of Arkansas when policies encourage a more efficient use of energy resources. Further discussion in this section will provide an overview of the DEEPER model and more detailed background information for the state of Arkansas.

Table 6-1. Economic Impact of Energy Efficiency Investments in Arkansas

Macroeconomic Impacts	2015	2020	2025
Net Jobs (Actual)	7,820	6,828	11,399
Wages (Million $2007)	$254	$175	$306
GSP (Million $2007)	$360	$119	$238

Methodology

This macroeconomic evaluation consists of three steps. First, we calibrate ACEEE's economic assessment model called DEEPER (or the Dynamic Energy Efficiency Policy Evaluation Routine) to reflect the economic profile of the Arkansas economy (IMPLAN 2010). This evaluation is done for the period 2007 (the base year of the model) through 2025 (the last year of this particular analysis). In this

[48] As we use the term here, the word "consumer" refers to any one who buys and uses energy. Thus, we include both households and businesses as among the consumers who benefit from greater investments in energy efficiency.
[49] As we note elsewhere, the policy analysis ends in the year 2025. Yet, many of the investments we describe have a technology of perhaps 15 years. This means that investments made in 2025 would continue to pay for themselves through perhaps the year 2040 and beyond; and none of those ongoing energy savings is reflected in the analysis described in this chapter.

respect, we incorporate the anticipated investment and spending patterns that are suggested by the standard forecast modeling assumptions. These patterns range from typical spending by businesses and households in the analytical period to the anticipated construction of new electric power plants and other energy-related spending that might also be highlighted in the forecast. Second, we transform the set of key efficiency scenario results from the policy analysis into the direct inputs which are needed for the economic model. The resulting inputs include such parameters as:

- The level of annual policy and/or program spending that drives the key policy scenario investments;
- The capital and operating costs associated with more energy efficiency technologies;
- The energy bill savings that result from the various energy efficiency policies described in the main body of the report; and
- Finally, a set of calibration or diagnostic model runs to check both the logic and the internal consistency of the modeling results.

So that we can more fully characterize the analysis that was completed for this report, we next provide a simplified working example of how the modeling is done. We first describe the financial assumptions that underpin the analysis. We then highlight the analytical technique by showing the kinds of calculations that are used and then summarize the overall results in terms of net job impacts. Following this example, we then review the net impacts of the various policies as evaluated in our DEEPER model.

Illustrating the Methodology: Arkansas Jobs from Efficiency Gains

To illustrate how a job impact analysis might be done, we will use the simplified example of installing one hundred million dollars of efficiency improvements within large office buildings throughout Arkansas. Office buildings—traditionally large users of energy due to heating and air-conditioning loads, significant use of lighting and electronic office equipment, and the large numbers of persons employed and served—provide substantial opportunities for energy-saving investments. The results of this example are summarized in Table 6-2.

Table 6-2. Illustrative Example: Jobs Impacts from Commercial Building Efficiency Improvements

Expenditure Category	Amount (Million $)	Employment Coefficient	Job Impact
Installing Efficiency Improvements in Year One	$100	12	1,200
Diverting Expenditures to Fund Efficiency Improvements	-$100	11	-1,100
Energy Bill Savings in Years One through 15	$200	11	2,200
Lower Utility Revenues in Years One through 15	-$200	4	-800
Net 15-Year Change	$0.0		1,500

Note: The employment multipliers are adapted from the appropriate sector multipliers within the Arkansas version of the DEEPER model. The benefit-cost ratio is assumed to be 2.0. The column marked "job impact" is the result of multiplying the row change in expenditure by the row multiplier. The sum of these products yields a working estimate of total net job-years over the 15-year time horizon. To find the average annual net jobs in this simplified analysis we would divide the total job-years by 15 years which, of course, gives us an estimated net gain of 100 jobs per year for each of the 15 years.

The assumption used in this example is that the investment has a positive benefit-cost ratio of 2.0. In other words, the assumption is that for every dollar of cost used to increase a building's overall energy efficiency, the upgrades might be expected to return a total of two dollars in reduced electricity and natural gas costs over the useful life of the technologies. This ratio is similar to those cited elsewhere in this report. At the same time, if we anticipate that the efficiency changes will have an expected life of roughly 15 years, then we can establish a 15-year period of analysis. In this illustration, we further assume that the efficiency upgrades take place in the first year of the analysis, while the electricity bill savings occur in years one through 15.

The analysis assumes that we are interested in the net effect of employment and other economic changes. This means we must first examine all changes in household and business expenditures—both positive and negative—that result from a movement toward greater levels of energy efficiency. Although more detailed and complicated within the DEEPER model, for this heuristic exercise we then multiply each change in expenditures by the appropriate sector employment coefficient as they are adapted from the IMPLAN (2010) data. The sum of these products will then yield the net result for which we are looking.

In our example above, there are four separate changes in expenditures, each with their separate impact. As Table 6-2 indicates, the net impact of the scenario suggests a cumulative gain of 1,500 jobs in each of the 15-year period of analysis. This translates into an average net increase of 100 jobs each year for 15 years. In other words, the $100 million efficiency investment made in Arkansas' office buildings is projected to sustain an average of 100 jobs each year over a 15-year period compared to a "business-as-usual" scenario.

The economic assessment of the alternative energy scenarios was carried out in a very similar manner as the example described above. That is, the changes in energy expenditures brought about by investments in energy efficiency and renewable technologies were matched with their appropriate employment multipliers. There are several modifications to this technique, however.

First, it was assumed that only 80% of the energy bill savings are spent within Arkansas. We base this ratio on the consumer spending patterns reflected in the IMPLAN (2010) dataset as it describes local purchase patterns that typically now occur in the state. We also anticipate that 90% of the efficiency installations are likely (or could be) carried out by local contractors and dealers. If the set of policies encourages greater local spending so that the in-state consumer share was increased to 90%, for example, the net jobs might grow another 25% compared to our standard scenario exercise. At the same time, the scenario also assumes Arkansas provides only 60% of the manufactured products consumed within the state. But again, a concerted effort to build manufacturing capacity for the set of clean energy technologies would increase the benefits from developing a broader in-state clean energy manufacturing capability.

Second, an adjustment in the employment impacts was made to account for assumed future changes in labor productivity. As outlined in the Bureau of Labor Statistics Outlook 2008–2018, productivity rates are expected to vary widely among sectors (BLS 2010). For instance, drawing from the BLS data we would expect that electric utilities might increase labor productivity by 2.8% annually while the economy as a whole might increase productivity by 1.9% per year. This means, for example, that we might expect a one million dollar expenditure for utility services in the year 2025 would support only 61% of the jobs that the same expenditure would have supported in 2007 (the base year of the model), while other sectors of the economy would support only 71% of the jobs as in 2007.

Third, for purposes of estimating energy bill savings, it was assumed that retail electricity prices in Arkansas would follow the same growth rate as that described in the reference case section. Fourth, it was assumed that the efficiency investments' upgrades are financed by bank loans that carry an average 7% interest rate over a five-year period. To limit the scope of the analysis, however, no parameters were established to account for any changes in interest rates as less capital-intensive technologies (i.e., efficiency investments) are substituted for conventional supply strategies, or in labor participation rates—all of which might affect overall spending patterns. Fortunately, however, it is unlikely that these sensitivities would greatly impact the overall outcome of this analysis.

While the higher cost premiums associated with the energy efficiency investments might be expected to drive up the level of borrowing (in the short term), and therefore interest rates, this upward pressure would be offset to some degree by the investment avoided in new power plant capacity, exploratory well drilling, and new pipelines. Similarly, while an increase in demand for labor would tend to increase the overall level of wages (and thus lessen economic activity), the job benefits are small compared to the current level of unemployment or underemployment in the state. Hence the effect would be negligible.

Fifth, as described in the previous chapters for the buildings, industrial, and transportation end-use sectors it was assumed that a program and marketing expenditure would be required to promote market penetration of the efficiency improvements. Since these vary significantly by policy bundle we don't summarize them here but payment for these policy and program expenditures were treated as if new taxes were levied on the state commensurate with the level of energy demands within the state. Hence, the positive program spending impacts are offset by reduced revenues elsewhere in the economy.

Sixth, it should be noted that the full effects of the efficiency investments are not accounted for since the savings beyond 2025 are not incorporated in the analysis. Nor does the analysis include other benefits and costs that can stem from the efficiency investments. Non-energy benefits can include increased worker productivity, comfort and safety, and water savings, while non-energy costs can include aesthetic issues associated with compact fluorescent lamps and increased maintenance costs due to a lack of familiarity with new energy efficiency equipment (EPA 2007d). Productivity benefits, for example, can be substantial, especially in the industrial sector. Industrial investments that increase energy efficiency often result in achieving other economic goals such as improved product quality, lower capital and operating costs, increased employee productivity, or capturing specialized product markets (see, for example, Worrell et al. 2003).

To the extent these "co-benefits" exceed any non-energy costs, the economic impacts of an energy efficiency initiative in Arkansas would be more favorable than those reported here. Finally, although we show in Table 6-2 above just how the calculations would look from an employment perspective, we don't show the same kind of data or assumptions for either income or for impacts on the Gross State Product (GSP, or the sum of value-added contributions to the Arkansas state economy). Nonetheless, the approach is very similar to that described for net job impacts.

Impacts of Recommended Energy Efficiency Policies

For each year in the analytical period, the given change in a sector spending pattern (relative to the reference scenario) was matched to the appropriate sector impact coefficients. Two points are worth special note: first, it was important to match the right change in spending to the right sector of the Arkansas economy; and second, these coefficients change over time. For example, as previously suggested, labor productivity changes mean that there may be fewer jobs supported by a one million dollar expenditure today compared to that same level of spending in 2025. Both the negative and positive impacts were summed to generate the estimated net results shown in the series of tables that follow. Presented here are two basic sets of macroeconomic impacts for the benchmark years of 2010, 2015, 2020, and 2025. These include the financial flows that result from the policies described in the previous chapters. They also include the net jobs, income, and GSP impacts that result from the changed investment and spending patterns.

Table 6-3 presents the changes in consumer expenditures that result from these policies. While the first row in the table presents the full cost of the energy efficiency policies, programs and investments, the utility customers will likely borrow all or at least a portion of the money to pay for these investments, repaying the debt over the course of the study period. Thus, "annual consumer outlays," estimated at $31 million in 2010, rise to $1.1 billion in 2025. These outlays include actual "out-of-pocket" spending for programs and investments, along with money borrowed to underwrite the larger technology investments. The annual energy bill savings reported here are a function of reduced energy and gasoline purchases.

As we further highlight in Table 6-3, the annual energy bill savings begins with a net gain of $71 million, reflecting the large investment required to get programs and infrastructure in place before savings can truly being to accrue. However, as more investments are directed toward policies and programs and the purchase of more energy-efficient technologies, the investments are paid back in lower energy bills and the net cumulative savings quickly build up, reaching almost $800 million net annual savings in 2025. Cumulative net energy bill savings reach over $3.2 billion for consumers in Arkansas by 2025.

Table 6-3. Financial Impacts from the Energy Efficiency Policy Medium Case Scenario

(Millions of 2007 Dollars)	2010	2015	2020	2025
Annual Consumer Outlays	$31	$507	$909	$1,117
Annual Energy-Bill Savings	$71	$497	$1,117	$1,897
Annual Net Consumer Savings	$40	-$11	$208	$780
Cumulative Net Energy-Bill Savings	$40	$198	$623	$3,224

- 'Annual' refers to the total that is reported in the benchmark year while 'Cumulative' is the total from previous years beginning in 2010 through the benchmark year.
- Annual consumer outlays include administrative costs to run programs, incentives provided to consumers, investments in efficiency devices and interest paid on loans needed to underwrite the needed efficiency investments.
- Annual energy bill savings is the reduced expenditures for energy services that benefit both households and businesses within a given year. The net savings is the difference between savings and outlays.

Now that we have estimates of how financial flows are distributed across the end-use sectors, we can assess the impacts on the state economy using the DEEPER model. The model evaluates impact on jobs and wages sector by sector, and evaluates their contribution to Arkansas' Gross State Product, which is a sum of the net gain in value-added contributions provided by the energy productivity gains throughout all sectors of the state economy. As with the previous table on financial impacts, for reader convenience, Table 6-4 repeats the net economic impacts.

Table 6-4. Economic Impact of Energy Efficiency Investments in Arkansas

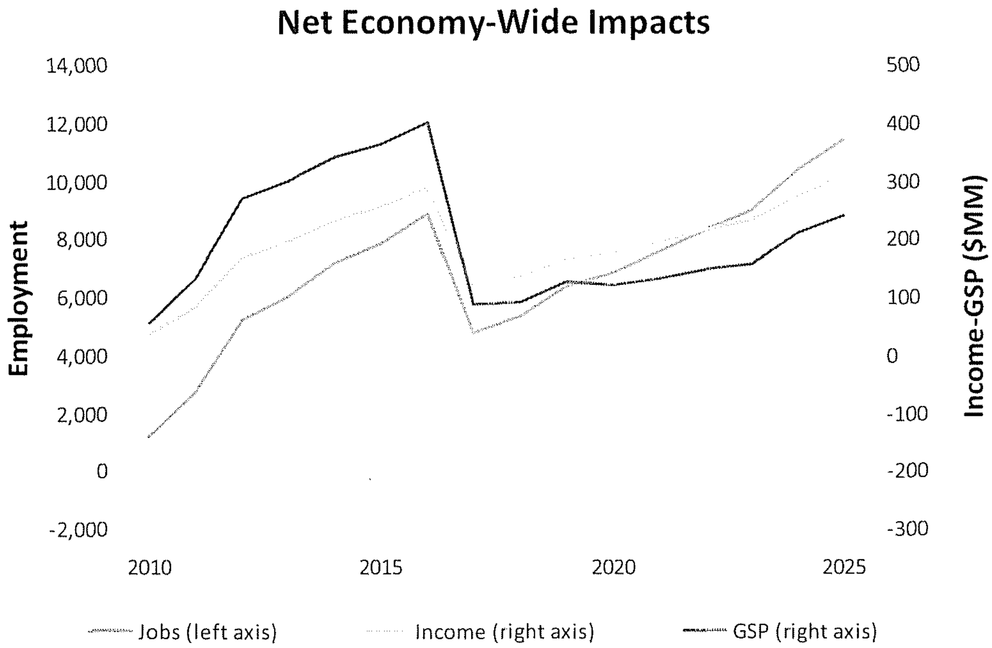
Macroeconomic Impacts	2010	2015	2020	2025
Net Jobs (Actual)	1,178	7,820	6,828	11,399
Wages (Million $2007)	$34	$254	$175	$306
GSP (Million $2007)	$54	$360	$119	$238

Given both the financial flows and the modeling framework, the analysis suggests a net contribution to the state's employment base as measured by full-time jobs equivalent. Assuming there is an immediate set of investments in 2010, the employment benefit begins almost immediately with a net gain of about 1,100 jobs. By the year 2015 we see a net increase of over 7,800 jobs, which increases to a significantly larger total of almost 11,400 jobs by 2025.

In Arkansas, the electric power and the natural gas service sectors directly and indirectly employ about 4 jobs for every $1 million of spending. But, all other sectors, including those vital to energy efficiency improvements like manufacturing and construction, utilize 11 jobs per $1 million of spending. Once job gains and losses are netted out in each year, the analysis suggests that, by diverting expenditures away from non-labor intensive energy sectors, the cost-effective energy policies can positively impact the larger Arkansas economy—even in the early years, but especially in the later years of the analysis as the energy savings continue to mount.

To highlight the results of this analysis in a little more detail, Figure 6-1 provides year-by-year impacts of the energy efficiency policies on net jobs in Arkansas and the anticipated net gain to the state's wage and salary compensation and Gross State Product, both measured in millions of 2007 dollars.

Figure 6-1. Net Employment, Wages, and Gross State Product Impacts for Arkansas in Medium Case Policy Scenario (2010–2025)



The results of the policy analysis suggests that an early program stimulus that drives a higher level of efficiency investments can actually increase the robustness of the Arkansas economy, creating about 7,800 *net* new jobs in 2015, and rising to about 11,400 net new jobs in 2025. This is roughly equivalent to the employment that would be directly and indirectly supported by the construction and operation of 90 small manufacturing plants within Arkansas. As indicated by Figure 6-1, these investments also increase both wages and gross state product throughout Arkansas. It is important to note that, as highlighted in Figure 6-1, infrastructure investments decline sharply around 2016 as a result of our assumed completion of the light rail projects analyzed in our transit-oriented development policy recommendation. While jobs decline quickly as a result of the reduced investments (note the difference in net job gains in Table 6-4 and Figure 6-1 between 2015 and 2020), jobs begin to increase again shortly thereafter as energy savings and demand for relevant goods and services rise. It is also worth noting that a more complete analysis of the *non-energy* or *productivity* benefits of energy efficiency investments would likely increase the overall GSP impacts to make them less negative or even positive. There is growing literature that documents several categories of "non-energy" financial benefits in addition to the anticipated energy bill savings (Laitner 2009). These additional savings include reduced operating and maintenance costs, improved process controls, increased amenities or other conveniences, and direct and indirect economic benefits from downsizing or elimination of other equipment (Worrell et al. 2003). The non-energy or productivity benefits can amplify energy bill savings by an additional 20 to 40% or more.

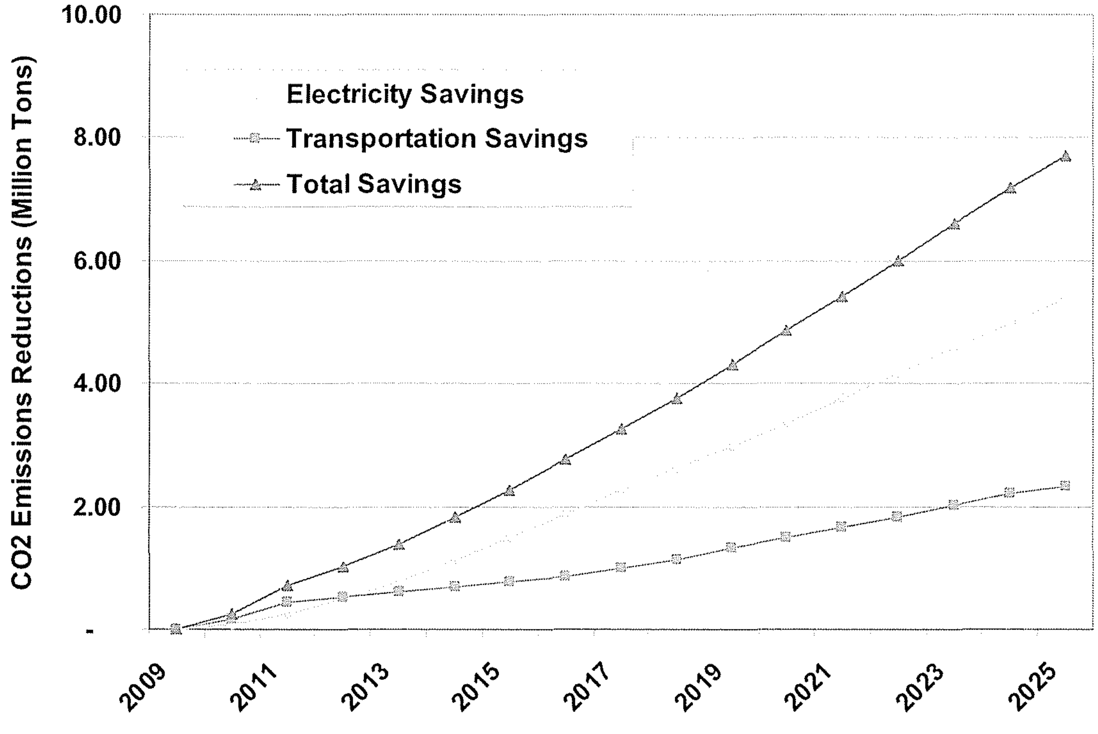
In short, the more efficient use of energy resources provides a cost-effective redirection of spending away from less labor-intensive sectors into those sectors that provide a greater number of jobs throughout Arkansas. Similarly, cost-effective energy productivity gains also redirect spending away from sectors that provide a smaller rate of value-added into those sectors with slightly higher levels of value-added returns per dollar of revenue. The extent to which these benefits are realized will depend on the willingness of business and policy leaders to implement the recommendations that are at the heart of this report and found earlier in this assessment. Indeed, to the extent that business and policy leaders go beyond the recommendations described here, the evidence further suggests an even greater net positive impact on the Arkansas economy.[50]

Emissions Impacts

Meeting the demand for electricity through efficiency resources reduces electricity generation, which has a concomitant impact on emissions that are a by-product of that generation. Thus, energy efficiency also represents a cost-effective strategy to reduce global warming emissions. One caveat of the avoided emissions from efficiency that readers should note is that Arkansas exports about 14% of its electricity. Therefore, not all of the electricity avoided through efficiency is attributable to power plants in Arkansas. Instead, the avoided emissions resulting from expanded energy efficiency in Arkansas will have both a local and regional impact.

The electric and transportation policies we suggest would reduce carbon dioxide (CO_2) emissions by 2.3 million tons in 2015 and almost 8 million tons in 2025, about 26% of total emissions in Arkansas (see Figure 6-2). Through 2025, energy efficiency can reduce CO_2 emissions cumulatively by almost 60 million tons. See Appendix B.2 for our detailed methodology.

Figure 6-2. Carbon Dioxide Emissions Savings from Electricity and Transportation Policies



[50] As a further thought experiment, we ran the DEEPER model to test the potential impact of both greater in-state spending that might result from the set of policies characterized in this analysis, and from the inclusion of non-energy benefits that are likely to follow from this policy scenario. Following an analysis by Laitner and Lung (2009), we conservatively assumed a set of non-energy benefits that might be about 40% of the electricity bill savings throughout the economy. With that change the net employment impacts rose from 9,500 jobs in the year 2025 to nearly 13,000 jobs in that same year. Moreover, GSP went from essentially a net-zero impact (slightly negative in some years and slightly positive in other years) to strongly positive in all years, reaching a total net benefit of $275 million by 2025.

Chapter Seven: Discussion and Recommendations

The primary goals of this study were twofold: (1) to characterize the overall cost-effective energy efficiency resource potential in Arkansas; and (2) to develop a suite of possible energy efficiency and demand response policies for the state and assess their energy and economic impacts. The results of the suggested policy suite are intended to assist state policy leaders, legislators, and regulators to develop high-level policies and regulations, while the results of the cost-effective resource assessment are intended to provide policymakers a degree of confidence in the reasonableness of the suggested policy suite and its impacts. Readers should note that the resource assessment is not intended to provide detailed energy efficiency *program* plans that will be needed to capture the savings we have identified in this study. Further analysis will be required in the near future to help design and augment new and existing programs.

In its *Rules for Conservation and Energy Efficiency Programs*, the PSC has already codified the requisites for energy efficiency program development, complemented by the PSC's *Rules and Regulations Governing Promotional Practices of Electric and Gas Public Utilities*. The PSC's omnibus order, released February 3, 2010, listed eleven issues that will be resolved in future dockets in order to maximize the potential benefits of implementing energy efficiency programs and policies across all sectors of Arkansas' economy. ACEEE's list of policy recommendations should be used as a resource to help shape programs as the state and its utilities continue to invest in energy efficiency programs in the future, as guided by the PSC.

In the section below we offer insight on several issues not covered in the discussion of our policy recommendations, but that will have to be addressed as the state progresses down its path towards a clean energy future.

Fuel Switching

In Arkansas, there is presently a PSC decision that utilities are not permitted to encourage customers to switch from one fuel to another (see PSC Rules and Regulations Governing Promotional Practices of Electric and Gas Public Utilities). Several gas utilities have proposed that this decision be changed and that they be allowed to promote natural gas use where it is in customers' economic interest to do so. There are some opportunities to save money and to save energy on a primary basis (meaning considering the fuel burned at the power plant) by switching from electricity to natural gas and visa versa. For example, natural gas space and water heating is generally more efficient than electric resistance systems, although the savings are reduced and sometimes eliminated relative to heat pumps. Conversely, highly focused electric heating technologies, such as industrial use of microwaves and induction heating, can be more efficient than natural gas systems.

In some states, fuel-switching is a permissible use of energy efficiency funds, provided the new system saves energy, reduces emissions, and saves consumers money, and ACEEE supports this approach. On the other hand, discussions on fuel switching are generally very contentious and tend to generate more heat than illumination. There are generally more productive and cost-effective energy efficiency investments than fuel switching. Even so, given the relative efficiency of heating with natural gas versus electricity, especially in residential applications, there are clear long-term benefits that could be realized through fuel-switching. Nonetheless, because Arkansas still has much to gain from the augmentation of its Quick Start programs, we recommend that discussions on fuel switching in Arkansas be deferred for a year or so that available time and resources can first be focused on the topic of expanding cost-effective core energy efficiency programs.

Independent Administration

In Arkansas, energy efficiency programs are mostly run by electric and gas utilities, although some programs are run by the State Energy Office (e.g., Industry Clearinghouse and Building Training Centers of Excellence) and by other state and local agencies (e.g., the Weatherization Assistance Program).

Some parties before the PSC have suggested that Arkansas move to a third-party program administrator and the PSC has agreed to consider this issue as part of Docket # 10-010-U.

In most of the U.S., efficiency programs are primarily implemented by utilities, but there are some notable exceptions. In Vermont, programs are administered by Efficiency Vermont, a statewide program implementer chosen by the Vermont Public Service Board through a competitive solicitation. In Oregon, most programs are run by the Energy Trust of Oregon, a statewide nonprofit organization. In Maine, the programs have been run by the PSC, but are now transitioning towards a third-party administrator, Efficiency Maine Trust. Wisconsin has moved from utility administration to a hybrid in which most programs are administered by third-party contractors, with the Wisconsin Public Service Commission responsible for general oversight, evaluation, and contracting with the third-party administrators. Similarly, the Indiana Utility Regulatory Commission has recently issued a ruling to move the substantial majority of programs in Indiana to third-party administrators chosen collectively by the state's utilities. New Jersey is another state with periodic changes, with programs originally administered by utilities, now administered by the Board of Public Utilities, but with a pending proposal for administration to revert back to the utilities, since state administration has proved cumbersome in practice. Similarly, in New York, programs were originally administered by utilities, reverted to a statewide "Authority" (the New York State Energy Research and Development Authority, NYSERDA), and now is a hybrid with some utility and some NYSERDA programs. Hybrids are also in place in Maryland and Illinois where most programs are administered by utilities and some administered by state agencies. Delaware also appears to be moving to a hybrid

Where there is non-utility administration, it is sometimes in states where utilities at the time preferred not to administer programs (e.g., Wisconsin, New York, and Vermont). Also, several of these states had existing in-state organizations and/or resources, to make independent administration quickly feasible (e.g., New York with NYSERDA, Vermont with the Vermont Energy Investment Corporation, and Oregon with a local core of experienced staff who quickly built up the Energy Trust of Oregon). Where there wasn't such an organization or core, developing a non-utility administrator has generally been a slow and difficult process, with major reassessments and changes along the journey (e.g., Wisconsin, Maine, New Jersey, and Delaware). On the other hand, for utility administration to work, the utilities have to really want the programs to work and achieve substantial savings. Several states have moved to non-utility administration because utility interest and support was lackluster (e.g., Vermont, New York, Maine, and Wisconsin).

In Arkansas, moving to non-utility administration would be challenging, since there is not an obvious in-state organization that could run the programs. Non-utility administration would most likely involve hiring out-of-state contractors, to be overseen by some agency or Board. Such a process would be time-consuming and difficult to set up. On the other hand, it is unclear whether Arkansas utilities truly want substantial energy efficiency programs to succeed in Arkansas. The Arkansas utilities are supporting efficiency programs, but so far only modest efforts. However, uncertainty created by the lack of utility incentives and lost revenue recovery is likely a contributing factor to the level of energy efficiency being pursued by Arkansas' utilities. Uncertainty about the entity responsible for the future administration of the programs may play a role as well. We urge the Commission to follow our recommendations regarding financial incentives for utilities in order to remove what we think is the primary uncertainty hindering the expansion of utility programs. In addition, utilities would like a final decision concerning the use of an independent administrator as well, arguing that this would provide them with the confidence that the Commission is committed to utility-administered programs. If the utilities were to truly embrace much more substantial efforts, we think they could do a reasonable job running them. But if they either oppose substantial programs, or such support is half-hearted, then non-utility administration should be seriously considered.

Separate from the question of who administers the programs is whether each utility should do its own program or whether the utilities should work together on statewide programs, at least for the major programs that serve many customers. Arkansas has a patchwork of utility service territories, with many regions served by more than one investor-owned utility and many coops interspersed. If each utility runs its own program, then it would be more difficult for customers, retailers and contractors to know who is eligible for which program, creating confusion and likely hampering participation rates. To address this, quite a few states have encouraged or required utilities to work together to develop common eligibility levels, incentives, and other program features (e.g., California, Connecticut, Massachusetts, and New York). And as noted above, a couple of states (Wisconsin and Indiana) have gone a further step and required utilities to hire common contractors to run programs statewide.

Chapter Eight: Conclusions

Recent action by the PSC has shown that Arkansas expects energy efficiency to play a major role in Arkansas energy policy for years to come. Arkansas has chosen to continue to fund and augment its current energy efficiency programs and policies, which will help to create new, local jobs for Arkansans; lower consumer energy bills; and stimulate economic development and demand for energy efficiency products produced by Arkansas manufacturers. Although investments in additional capacity will still be necessary in the future, that need will be considerably reduced. No longer will Arkansas limit itself to a path where load growth is met by costly investment in new generation resources, costs which are ultimately passed on to consumers in the form of higher rates with little done to train and prepare Arkansans to participate in and contribute to a 21st century, clean energy economy.

At the behest of the PSC, Arkansas utilities made modest investments in efficiency programs in the roughly two-and-a-half year Quick Start phase, which ended December 31, 2009. With guidance from the PSC on the direction of the comprehensive phase issued in 10 Orders on December 10, 2010, utilities are shifting gears to get their programs ready, with program and budget proposals due by April 1, 2011 for the 2011 program year. Meanwhile, the Arkansas Energy Office is occupied with the task of distributing millions of dollars in stimulus funding towards over a dozen energy programs aimed at stimulating economic development and creating jobs by way of expanding the market for energy efficiency goods and services, as well as developing programs to help train those individuals who will be responsible for delivering the services on the ground. The PSC and the AEO are both in a position to significantly influence the focus of Arkansas energy policy over the next several decades, so it is vital that both entities strongly consider their options and make prudent investments to ensure that Arkansas is able to continue to compete in the national economy.

Arkansas' Future with Energy Efficiency

In this study we have recommended and discussed a number of policies that could be implemented to help generate considerable energy savings across all sectors of Arkansas' economy, as well as a number of enabling policies that would help facilitate the development of these policies and programs. Many of the topics covered in the 10 Orders were based off the work conducted in this study by ACEEE. To review, there are a number of priorities that, if prudently addressed, will increase the potential for these programs to succeed.

A critical issue moving forward is the establishment of energy-saving targets for utilities in the form of an energy efficiency resource standard. The PSC has adopted an EERS as part of the 10 Orders issued in December, although the savings targets are modest and are only required for the next three years (Order No. 17, Docket # 08-144-U). The targets were set for an initial period of three years in order to determine if, during this period, "the comprehensive EE effort is capturing the greatest amount of cost-effective potential that can be effectively delivered." If it is determined by the PSC that the targets are being met cost-effectively, ACEEE strongly recommends that the PSC continue to require annual savings targets for their utilities and that these targets continue to ramp up over time.

However, since utilities are private businesses and are therefore required to earn a return for their shareholders, it is equally critical that increased investment in utility-funded efficiency programs is remunerated through the offering of mechanisms addressing lost-revenues and also the offering of shareholder incentives, where utilities are rewarded financially for meeting and exceeding the annual targets set by an EERS. The PSC is cognizant of this issue and as a result approved "each component of the 'three legged milk stool' that utilities have argued is necessary to remove all utility disincentives to energy efficiency program implementation. These components include recovery of direct program costs, approval of a lost-contribution-to-fixed-costs mechanism, and performance incentives (Order No. 15, Docket # 08-137-U).

To support these programs, a primary concern moving forward is that the comprehensive phase of Arkansas' energy efficiency programs is aggressive and adequately funded and staffed. From public outreach to training auditors, evaluators, and operators, the state and its utilities will need to ensure that the market for energy efficiency is robust so as to maximize participation and that there is enough qualified personnel to meet the demand created by investments in these programs. This means ensuring that the PSC and the AEO are also adequately funded and staffed so they are able to satisfy their obligations, such as overseeing measurement and verification of utility programs (PSC) and continuing to offer and administer state and nationally-funded energy programs that will help shape the market and future energy policy in Arkansas (AEO).

Finally, a key component to ensuring the efficacy of energy efficiency policies and programs is the implementation of a proper evaluation, measurement, and verification mechanism (EM&V). Actively pursuing energy efficiency requires that programs are being rigorously monitored and evaluated. Without detailed reporting from utilities on the successes (or failures) of their efficiency programs, improving the programs over time will be difficult. Transparency of the investments and savings realized by these programs will make it easier to determine how the programs can be modified or augmented in order to generate greater cost-effective savings in the future. Included in the 10 Orders issued by the PSC was an Order to direct the convening of a collaborative through which an EM&V protocol will be developed. The EM&V protocol will be used to determine the amount of incentives awarded to utilities (Order No. 15, Docket # 08-137-U) as well as an alternative method of calculating utilities' lost contribution to fixed costs in the absence of approved deemed savings (Order No. 14, Docket # 08-137-U).

Arkansas has already shown it is poised to embrace a clean energy future and recent policy developments have reinforced its position. But meeting this goal will require a concerted effort from all parties: the PSC, the AEO, the State Legislature, Arkansas utilities, businesses, and the general public. If all parties are willing to compromise to find a path forward that is mutually beneficial, the state, its businesses, and its consumers will reap the benefits for years to come.

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Appendix A—Reference Case

A.1. Projection of Energy Consumption

The development of the reference case for Arkansas is the foundation of the quantitative analysis of the report. The first task in developing an energy efficiency and demand response potential assessment is to determine a reference case forecast of energy consumption, peak demand, and electricity prices in the state in a "business as usual" scenario. As with all forecasts, they are subject to significant uncertainty, particularly in times such as we are in when the economic outlook is a major unknown. It is however important to understand that while the forecast may affect the final numbers resulting from the analysis, that the forecast has very minor impact of the effectiveness of the proposed policies, particularly in the long-run.

Modified Reference Case

Forecasts often do not account for reduced consumption that arises from energy efficiency and demand response programs initiated by utilities, nor do they account for energy savings from consumers' purchase of more efficient appliances and equipment. These savings should not be ignored as their accumulation lessens the burden of achieving any state-mandated savings target, such as an energy efficiency resource standard. While Arkansas has not implemented its own appliance efficiency standards, the Department of Energy is actively developing and mandating standards and is scheduled to implement standards on over two dozen products by 2013.[51] The following section provides greater detail about our "modified" reference case, which is our consumption forecast net any savings accumulated through utility efficiency programs and federal appliance standards. We use the modified reference case as the base case consumption forecast through which we analyze the percent savings of the individual policies and utility programs.

Electricity (GWh)

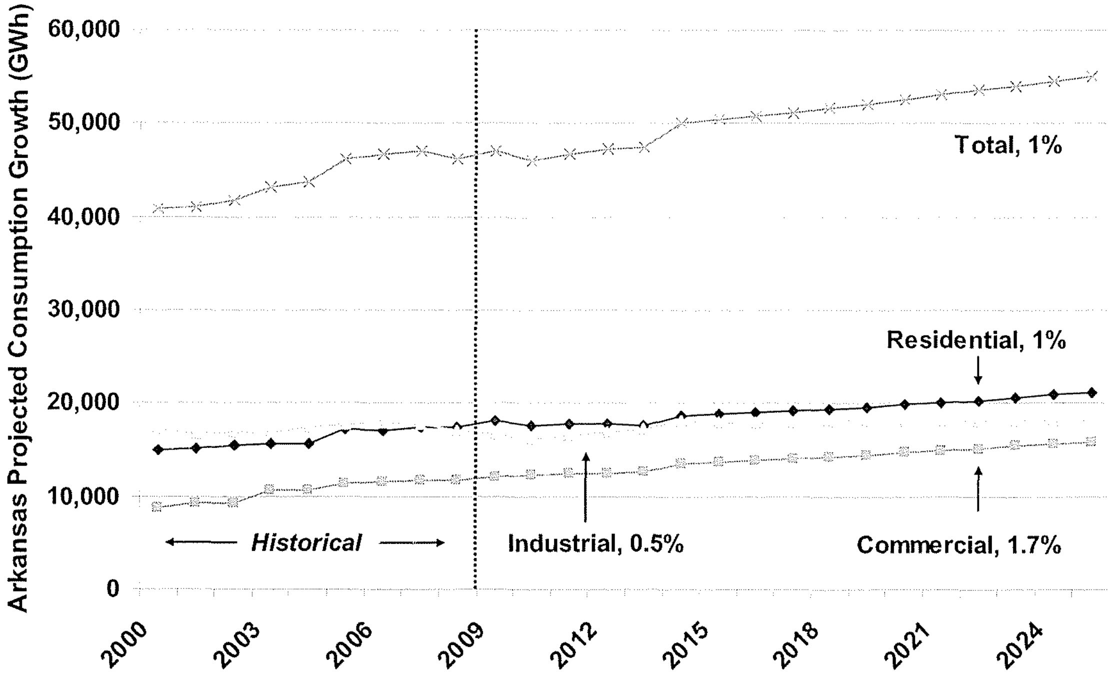
Arkansas' forecast of electricity consumption uses 2007-year actual sales reported to the Energy Information Administration as a baseline (EIA 2010b). The EIA's *Annual Energy Outlook* forecasts electricity consumption by sector by region, while its *Electric Power Annual* provides historical consumption data. In past state studies, where state-specific forecasts are inadequate or non-existent, ACEEE has projected consumption by applying sector-specific, regional growth rates taken from the AEO's regional forecasts to historical data provided by the *Electric Power Annual*. But regional data does not necessarily reflect trends that are unique to a state. Fortunately, ACEEE did not need to rely on regional data to develop the reference case forecast. For Arkansas, Synapse Energy Economics estimated our statewide sales forecast for electricity using load growth rates from Entergy's 2009 IRP as a proxy for growth in state sales.

Entergy's 2009 IRP provided three scenarios for load growth over the 2009–2020 period: reference, low, and high growth. Utilizing the reference scenario forecast and using 2007 as the base year, Synapse estimated annual growth rates by normalizing the growth rates derived from Entergy's IRP load forecast with a 2009 to 2007 load ratio calculated using Entergy's FERC 714 filings for summer peak for 2006 through 2008. These normalized load ratios were then applied to historical sales data to ascertain future sales growth in the state through 2020. Sales for 2021–2025 were estimated using the average annual

[51] The Department of Energy is scheduled to implement new federal appliance and equipment standards, as well as update current standards, for 26 products between 2009 and 2013. Included are standards for fluorescent and incandescent reflector lamps, central air conditioners and heat pumps, furnace fans, and residential water heaters, which represent some of the most energy-intensive appliances and equipment on the market. The analysis of the potential savings of these standards can be found in the Appliance Standards Awareness Project (ASAP) and ACEEE report entitled *Ka-Boom! The Power of Appliance Standards: Opportunities for New Federal Appliance and Equipment Standards* (Neubauer and deLaski 2009).

growth rate for sales between 2015 and 2020. Using this methodology, and accounting for savings from federal appliance standards, we estimate that total electricity consumption in the state will grow at an average annual rate of 1% between 2009 and 2025, and 1%, 1.7%, 0.5% in the residential, commercial, and industrial sectors, respectively (see Figure A-1). Actual electricity consumption in 2007 according to the 2007 EPA was 47,055 GWh, growing to 50,401 GWh in 2015 and 55,043 GWh in 2025.

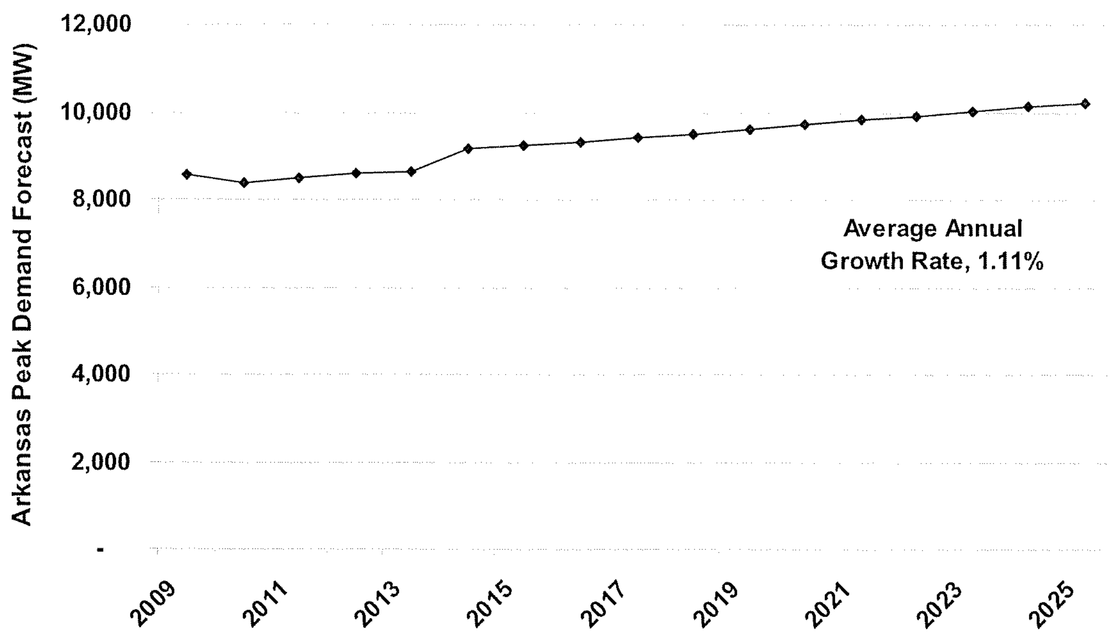
Figure A-1. Arkansas Electricity Consumption, Historical and Forecasted, 2000–2025



Peak Demand Forecast (MW)

Synapse utilized the sales forecast above and historical data from the EIA on average loss factor (13.36%) to estimate system peak demand for the state of Arkansas. Taking the sales forecast and adjusting for system losses, Synapse estimated an overall energy load. An assumed load factor of 62.7% was then applied to the estimates of Arkansas' energy load to determine system peak demand. Using this methodology, we estimate that peak demand in Arkansas will grow at an average annual rate of 1.11% between 2009 and 2025, reaching around 9,200 MW in 2015 and 10,200 MW in 2025 (see Figure A-2).

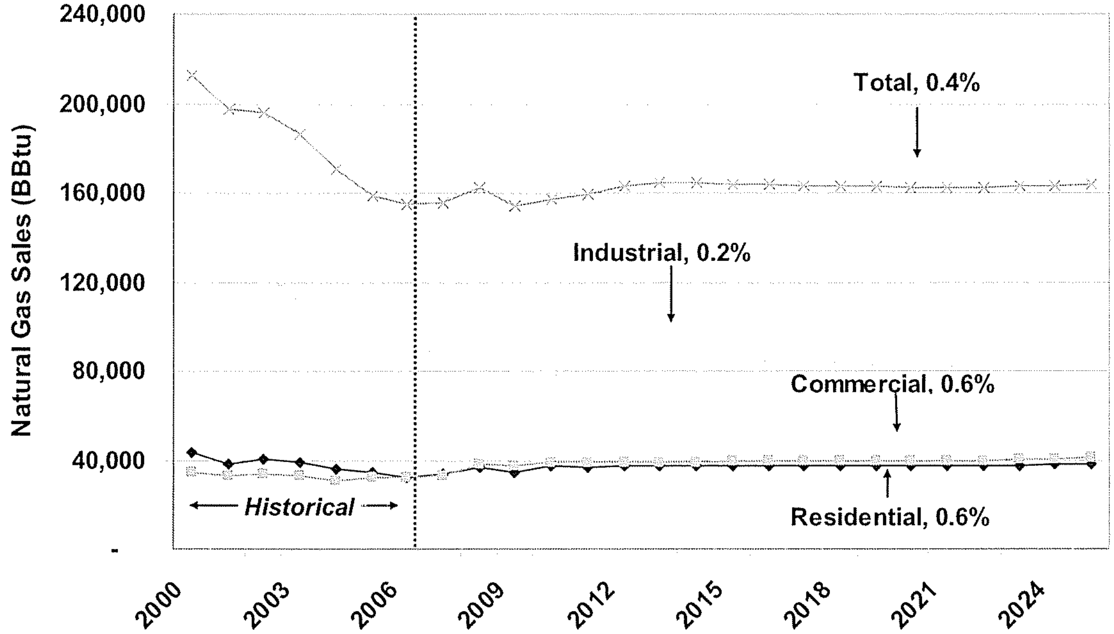
Figure A-2. Arkansas Peak Demand Forecast, 2009–2025



Natural Gas Forecast

Our forecast for natural gas consumption in Arkansas is based upon historical consumption data provided by the EIA's *Natural Gas Navigator*. To estimate projected consumption, we applied annual growth rates derived from the 2009 *Annual Energy Outlook* forecast for the West South Central region to state-specific historical data take from the Natural Gas Navigator. We then deducted estimated savings from federal appliance standards to generate our modified reference case. Using this methodology, we estimate that total natural gas consumption in the state will grow at an average annual rate of 0.4% between 2009 and 2025, and 0.6%, 0.6%, and 0.2% in the residential, commercial, and industrial sectors, respectively (see Figure A-3).

Figure A-3. Arkansas Natural Gas Consumption, Historical and Forecasted, 2000–2025 (BBtu)



A.2. Projection of Reference Case Supply Prices and Electricity Avoided Costs

This part of the appendix describes the key inputs to the electricity model (Electricity Avoided Cost Model) that Synapse Energy Economics has developed for the Arkansas (AR) project, the rationale for the proposed values of those inputs and the sources of those values.

The values of these inputs are provided in Attachment A to this memo, as well as in the EXCEL workbook titled ***AR Reference Case 2010-05-12.xls***. This workbook consists of two substantive worksheets—*"EIA State"* and *"Inputs"*:

- The EIA State worksheet contains all of the historic data that Synapse has downloaded from EIA for this project.
- The Inputs worksheet contains the values for each of the twelve categories of inputs. Also in this worksheet, below these inputs, are Synapse calculations that develop and support the input values.

We also provide a description of the Electricity Avoided Cost Model that will be used to estimate future production costs and avoided costs. A detailed description is provided in Appendix B. In summary, the Electricity Avoided Cost Model is a basic dispatch and production costing model implemented in Excel. It also calculates resource investment costs using exogenously specified additions and retirements based on current public plans.

Caveats

The projected electricity supply prices and avoided costs reported in this study are based upon a number of simplifying and conservative assumptions that we would not consider to be reasonable in other contexts. These include a simplified representation of avoided costs for different load factors and load shapes, and generic estimates of the capital costs of new resources.

Input Assumptions

The key inputs to the electricity model are presented under the following thirteen categories:

1. Basic Modeling assumptions
2. Base year Sales and revenues
3. Base year Load and resource Balance
4. In-State Base Year Generation Resource Performance and Cost Data
5. New Generation Resource Performance and Cost Data
6. Fuel Types
7. Annual Energy and Peak Load
8. Capacity retirements
9. Capacity additions
10. Fuel prices
11. Purchased Power Costs
12. Carbon Emission Costs
13. Wholesale Market Prices

Basic Modeling Assumptions

The base year is 2007. All monetary values are reported in constant 2007 year dollars unless noted otherwise. The study period begins in 2008 and ends in 2030, an analysis period of 23 years. The reporting period is 2009 through 2025, a total of 17 years. The financial parameters for costing resource additions are as follows:

- *Inflation Rate.* ***2.00%***. Based on analysis done for the New England AESC study[52] reflecting recent conditions.

- *Nominal Discount Rate.* ***10.0%***. This represents the value for an independent power producer with a mix of equity and bond financing. Based on a 50/50 equity/debt mix with 12% for equity and 8% for debt. Used for levelization of capital expenditures. Actual rates for specific projects will vary depending on the nature of the project and the implementing entity.

- *Real Discount Rate.* ***7.84%***. Derived from the Nominal Discount Rate and the Inflation Rate.

- *Income Tax Rate.* Federal rate of ***35%*** and AR state corporate rate of ***6.5%***. Property tax rate at the nominal level of ***0.5%*** per annum of the initial plant cost (local rates vary considerably). This is used for capital cost levelization.

Base Year Sales and Revenues

The historic sales and revenues data through 2007 are obtained from the EIA's "State Electric Profile" Table 8 (http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html) as of July 2009. The historic data indicates that AR is a modest net exporter and exports about 2% of its generation. Likewise in-state capacity is more than adequate to meet in-state peak loads.

Base Year Load and Resource Balance

The historic sales and revenues data are obtained from the EIA's "State Electric Profile" Tables 5, 8 and 10 (http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html) as of July 2009.

[52] "Avoided Energy Supply Costs in New England: 2009 Report", Synapse Energy Economics for the Avoided-Energy-Supply Component (AESC) Study Group, August 2009.

In-State Base Year Generation Resource Performance and Cost Data

From the above EIA data, we have the generation, CO2 emissions and fuel costs for each group or category of generating units, e.g., coal, natural gas combined cycle (NGCC), natural gas combustion turbine (NGCT), nuclear. From that data we can derive the average heat rate for each group and the fuel component of the generation costs. To that we add typical industry values for O&M. Also from that EIA data we have the historic capacity factors associated with resource group. Those historic patterns are used to set the basis for future performance.

New Generation Resource Performance and Cost Data

For new generation resources we have used the technology parameters from the AEO Assumptions document (EIA 2009). For capital costs we have used our professional judgment based on a number of sources to reflect current cost expectations for new construction.

Fuel Types

We use the three basic fossil fuel types (Coal, Petroleum and Natural Gas) as specified in the EIA's "State Electric Profile" with the addition of nuclear and biomass.

Annual Energy and Peak Load

For energy and peak loads we have used the Reference Case Forecast for Arkansas developed by ACEEE (1/14/2010) using information from the utility IRPs. This includes the effects of the current economic downturn and existing DSM programs with a resulting average growth rate of about 1% per year.

Capacity Requirements

There is limited information about future retirements of existing generating units and a variety of unknown circumstances may either work in favor of, or against, continued operation of individual units. It is however likely that some older less efficient generating units will be retired in the future. To reflect this we represent modest gradual retirement of existing units in the model. But it is possible that some existing units will be retrofitted and their lives extended.

Capacity Additions

In order to meet forecasted growth in annual energy and peak load in the Reference Case with an adequate reserve margin of 15%, new capacity must be added to the existing generation capacity. The assumption of a 15% reserve margin was taken from the 2007 National Electric Reliability Council Long-Term Reliability Assessment (NERC 2007). While utilities prefer to have utility-specific reserve margins referenced when estimating avoided costs, experience shows that reserve margins across utilities are not that disparate and can be overstated. The impact of the assumptions of reserve margins on the avoided cost analysis is a secondary concern in the overall analysis; accounting for minor variations across utilities would not affect the results significantly. Because the Electricity Avoided Cost Model is not a capacity expansion model we add new capacity resources "manually" Our analysis will consider three sets of capacity additions:

- Planned Capacity Additions—Near-term proposed new additions or uprates to existing plants that are in development or advanced stages of permitting and have a high likelihood of reaching commercial operation;
- Renewable Portfolio Standard (RPS) Capacity Additions—Renewable generators that are added to meet existing or anticipated RPS in each state;

- Generic Capacity Additions—New generic conventional resources that are added to meet any residual capacity need after Planned and RPS Capacity Additions.

Planned Capacity Additions

Description: Our near/intermediate-term entry forecast is based on projects in the most recent utility Integrated Resource Plans (IRP). These IRPs indicate additions from 2010 through 2020 of 1700 MW of coal, 2000 MW of NGCC, 250 MW of CTs, 760 MW of wind and 200 MW of biomass.

Data Sources: "Entergy Arkansas Integrated Resource Plan 2009" October 2009, "2009 AEP-SPP Integrated Resource Plan" July 2009 and "Oklahoma Gas & Electric Integrated Resource Plan 2010" January 2010.

Renewable Performance Standard Capacity Additions

There is no Renewable Performance Standard currently existing for Arkansas thus we have not included the effects of any in our reference data. However the utilities do have plans for some wind and biomass resources which are included in the planned additions. The operating characteristics are based on data from AEO and Synapse estimates derived from experience elsewhere in the US.

Generic Capacity Additions

Under the Reference Case, additional new capacity will be needed in the long-term portion of the forecast period after 2023. A range of generation technologies was considered for this purpose, including gas/oil-fired combined-cycle, gas/oil combustion turbines, conventional coal, and nuclear. Based on current utility plans we assume that these additions would be a mix of 75% NGCC and 25% NGCT. Our expectation is that no new coal plants will be built after 2020 unless they include carbon capture and storage for which the cost and feasibility are quite uncertain.

Fuel Prices

We start with fuel prices reported for the base year of 2007. For consistency and simplicity we used the base year historical prices and scaled them using the AEO 2009 Reference Case forecast[53] year to year changes for the Southeastern Electric Reliability Council (SERC) region.

Carbon Emission Costs

Carbon compliance costs are set at the Synapse 2008 medium case level (see "Synapse 2008 CO2 Price Forecasts", July 2008, David Schlissel et al).

Wholesale Market Structure and Prices

Arkansas is not part of a wholesale market *per se* although the interstate transactions are regulated by FERC. We assume that cost trends for those interstate power purchases and sales follow those for in-state power production.

A.3. Electricity Planning and Costing Model

This model was developed by Synapse for ACEEE's clean energy state studies.

[53] Annual Energy Outlook 2009 Reference Case, Energy Information Agency (EIA), March 2009. http://www.eia.doe.gov/oiaf/aeo/

Background

ACEEE has initiated a series of state-specific "Clean Energy" potential studies through which it will work with key stakeholders in order to build a common understanding of, and consensus on, the role that clean energy resources, i.e., energy efficiency and demand response, can play in meeting the future electricity end-use requirements in each state, the economic benefits of treating those resources as the "first fuel" for meeting future requirements and the policies for maximizing reliance upon those resources. The time horizon for the studies is through 2025.

In each of those studies ACEEE will evaluate the cost effectiveness of reductions from energy efficiency and demand response, and will also demonstrate the benefits of those reductions to all consumers in the state by estimating retail prices in the long-term under a clean energy Policy Case.

ACEEE retained Synapse to provide three deliverables to support these studies:

- Projections of long-term wholesale electricity supply prices under a reference, or business-as-usual case;
- Credible, consistent, "high-level" estimates of avoided electric energy ($/kWh) and capacity costs ($/kW-year); and
- Projections of long-term electricity supply prices under a clean energy policy case.

In light of time and budget constraints, and the policy nature of these studies, ACEEE requested that Synapse develop and apply an electricity planning and costing model that would produce accurate "high-level" estimates of each of these deliverables in a well-documented, transparent manner.

In order to satisfy the ACEEE request, Synapse had to develop an electricity planning and costing model that would be:

- Applicable to planning and costing from a state perspective, although most electric utility operations cross state boundaries;
- Applicable from state to state, although some states are part of deregulated multi-state markets while others operate under traditional utility regulation;
- Applicable using public data;
- Inexpensive to setup and run; and
- Relatively transparent.

Synapse has developed an EXCEL based planning and costing model with these characteristics.

Methodology

The model begins with an analysis of actual physical and cost data for a base year, develops a plan for meeting projected physical requirements in each future year of the study period and then calculates the incremental wholesale electricity costs associated with that plan. (Incremental to electricity supply costs being recovered in current retail rates).

Base Year Data

The actual data for the base year, and prior years, provides our starting point. That dataset contains historical data in the following categories:

1. Recent year summary statistics.
2. Listing of the ten largest plants in the state.
3. Top five providers of retail electricity
4. Electric capability by primary energy source.
5. Generation by primary energy source.
6. Fuel prices and quality.
7. Emissions.
8. Retail sales and revenues by customer class.
9. Retail sales by various provider types.
10. Supply and distribution of electricity.

This data enables us to characterize the electric supply system and its costs for a given state. For example the capacity, generation and capacity factor, average heat rate and fuel costs for different classes of resources. We can also calculate the retail margin from this data, i.e., the margin between average retail rates and variable production costs. The retail margin reflects the transmission and distribution costs being recovered in retail rates plus the fixed generation costs being recovered in those rates. This data is a very broad brush since the resources are grouped by fuel type and their operation is not characterized in great detail.

Future Years

We begin with the forecast of annual demand and energy in each future year provided by the ACEEE stakeholder group. Next we develop a physical plan to meet the load in each of those future years. This is done in the model via the following steps:

1. Derive annual capacity and generation requirements from forecast of retail annual demand and energy, and reserve margins;

2. Determine the relative quantities of annual capacity and generation to be provided by in-state and out-state resources based on the current mix of in-state and out-of state resources;

3. Estimate resource retirements. It is quite difficult to predict the timing of actual plant retirements, but it is reasonable to assume that some older facilities will be retired during the study period. We assume gradual retirement of existing resources over time based on typical operating lifetimes. This is explicitly specified in the input data section and can easily be modified if more specific data becomes available;

4. Estimate the capacity, timing and timing of new generation additions, in-state and out of state. Our model is not a capacity expansion model and therefore does not make capacity additions "automatically". Instead, after we include "planned" capacity additions, we add enough "generic" capacity additions to maintain the reserve margin. Our generic additions are a mix of peaking, intermediate and baseload units that maintains the historical mix of those categories in the state. This approach is transparent as the additions are explicitly specified in the input data section;

5. Calculate the quantity of annual generation from each category of capacity, existing and new, in-state and out of state. The estimated quantity of generation from each category of capacity is derived from the operating capacity factors. These are generally based upon economic dispatch, i.e., dispatch from each category in order of increasing variable production costs.

Calculate Average Production Costs (Average Supply Costs)

The model calculates the average production costs, i.e., energy plus capacity, for the particular case in the Production Model worksheet.

States with Regulated Wholesale Markets

For states with regulated wholesale markets the Production Model worksheet calculations are made as follows:

6. Calculate total cost of generation from existing in-state resources, purchases from out-of-state resources, and new in-state resources:
   a. The unit production costs of existing in-state generation includes variable operating costs plus fixed costs. The aggregate cost of generation from these resources decline over time as existing coal, oil and gas plants are retired, while the existing nuclear plants with low operating costs continue operation;

   b. The unit production costs of new in-state generation consists of the levelized capital cost of new capacity additions plus their variable operating costs. The capacity cost of new capacity additions are levelized using the capital recovery factors developed in the Capital Recovery Calculation (CRC) worksheet.

   c. The cost of power imported or exported is indexed to the generation-weighted average cost of generation from the in-state resources, i.e., existing and new. That is, the base-year import/export price changes in parallel with the in-state cost, e.g., an x% change of in-state production costs is reflected in an x% change of import/export prices. The rationale is that relative changes of in-state costs will be reflected outside the state as well.

States with De-Regulated Wholesale Markets

For states with de-regulated wholesale markets the Production Model worksheet calculations are made as follows:

7. The first step is to calculate the reference year market prices for the state being studied. The next step is to calculate the relationship between those state prices and market location for which future prices are available. The third step is to then apply that relationship to the futures prices to produce a forecast for market prices in the study state.

Calculate Avoided Costs

States with Regulated Wholesale Markets

For states with regulated wholesale markets the Production Model worksheet calculates the total avoided costs, avoided capacity costs and avoided energy costs via the following steps:

8. Total Avoided Costs. The worksheet calculates "all-in" avoided costs that include both energy and capacity costs.

   a. Years 1 to 5. For the first five years the avoided costs are a mix of avoided dispatch of existing resources and avoided total cost of new resources that would otherwise come-on-line during that period. The percentage of new resources included in that mix is phased-in, starting at 0% in year 1 and rising to 100% in year 5.

   b. Year 6 onward. After year 5 the avoided costs in each year equal the average total costs of new resources in that year. This calculation assumes that the capital costs of new resources are avoidable either through avoiding their actual construction or through recovery from revenues from off-system sales.

9. Avoided capacity cost. To estimate the avoided cost of capacity only we use the proxy plant approach which is used by several ISOs. This avoided capacity cost is based upon cost of

"capacity only" from a new gas combustion turbine "peaker" unit. Basing avoided capacity cost on the capital cost of a new peaker is a commonly accepted method.

10. Avoided Energy Cost. The avoided energy cost is the total avoided cost from step 8 minus the avoided capacity cost from step 9.

States with De-Regulated Wholesale Markets

For states with de-regulated wholesale markets the Production Model worksheet calculates the total avoided costs, avoided capacity costs and avoided energy costs differently for different time-periods.

11. Near-term years for which futures prices are available, e.g., first 4 to 5 years.

    a. Avoided energy cost—This is calculated from the energy futures market prices with appropriate historic-based adjustments for the state service area.

    b. Avoided capacity cost—This is based on the available appropriate capacity market results.

    c. Total avoided cost—This is obtained by combining the avoided energy cost with the avoided capacity cost using the base year system load factor to arrive at the combined total avoided cost on a per MWh basis.

12. Long-term years for which futures prices are not available. After the period for which futures are available, the total avoided costs, avoided capacity cost and avoided energy cost are developed in the same manner as for regulated states, in steps 8, 9 and 10.

A.4. Reference Case Electricity Supply Prices and Avoided Costs

The reference case load forecast, supply forecast, and supply prices by year are presented in Table A-1. The forecast of physical supply is set to equal the forecast of physical load plus the level of estimated losses in transmission and distribution. The supply prices consist of the projected wholesale electricity supply costs each year. The retail margin reflects the projected recovery of the costs of local transmission and distribution service. (Retail margin equals the base year average annual retail price minus base year average supply cost). It is assumed to remain constant in real dollars. The total average retail rate equals the supply cost plus the retail margin. The retail rate forecast only reflects the projected changes in energy supply costs.

The avoided costs are presented in Table A-2. The avoided capacity costs are presented in $/kW-year while the avoided electric energy costs are given in ¢/kWh. For consistency and simplicity we have based the avoided capacity costs on the net costs for a new NG CT peaker unit. In the future other capacity resources might be cheaper, or there might be limited need for new capacity because of reduced or declining load growth and renewable additions.

Table A-1. Reference Case Load, Supply and Price Forecasts

All costs in constant 2007 dollars.

CASE:	Preliminary AR Reference Case - 5/12/2010																	
Category	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load Forecast																		
Retail Energy	GWh	47,021	46,039	46,621	47,181	47,344	50,024	50,401	50,824	51,180	51,594	52,049	52,591	53,065	53,549	54,041	54,539	55,043
Retail Demand	MW	8,561	8,382	8,488	8,590	8,620	9,108	9,176	9,253	9,318	9,394	9,476	9,575	9,661	9,749	9,839	9,930	10,021
Supply Forecast																		
Capacity Requirement	MW	11,161	10,928	11,066	11,199	11,237	11,873	11,963	12,063	12,148	12,246	12,354	12,483	12,595	12,710	12,827	12,945	13,065
Capacity Sources																		
In-State Capacity	MW	15,297	15,313	15,842	15,922	16,899	16,909	16,926	17,104	16,782	16,461	16,796	16,455	16,093	15,732	15,469	15,841	15,898
Out-of-State Capacity	MW	-4,136	-4,385	-4,776	-4,723	-5,662	-5,036	-4,963	-5,041	-4,635	-4,215	-4,442	-3,972	-3,498	-3,022	-2,643	-2,896	-2,833
Total Capacity Provided	MW	11,161	10,928	11,066	11,199	11,237	11,873	11,963	12,063	12,148	12,246	12,354	12,483	12,595	12,710	12,827	12,945	13,065
Energy Requirement	GWh	53,304	52,191	52,850	53,486	53,670	56,709	57,136	57,616	58,019	58,489	59,004	59,619	60,156	60,705	61,263	61,827	62,398
Energy Sources																		
In-State Generation	GWh	60,688	59,421	60,171	60,895	61,105	64,564	65,050	65,597	66,056	66,591	67,177	67,877	68,490	69,114	69,749	70,391	71,041
Out-of-State Generation	GWh	-7,384	-7,230	-7,321	-7,409	-7,435	-7,855	-7,915	-7,981	-8,037	-8,102	-8,173	-8,259	-8,333	-8,409	-8,486	-8,564	-8,644
Total Energy Provided	GWh	53,304	52,191	52,850	53,486	53,670	56,709	57,136	57,616	58,019	58,489	59,004	59,619	60,156	60,705	61,263	61,827	62,398
Supply Price Forecast																		
Average Production Cost	¢/kWh	4.67	4.68	4.70	4.80	5.55	5.75	5.89	6.02	6.16	6.33	6.48	6.60	6.70	6.82	6.93	7.11	7.28
Retail Margin	¢/kWh	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02
Average Retail Rate	¢/kWh	6.68	6.69	6.72	6.81	7.57	7.77	7.91	8.04	8.18	8.35	8.50	8.62	8.71	8.84	8.95	9.13	9.30

Table A-2. Reference Case Avoided Costs

All costs in constant 2007 dollars.

CASE:	Preliminary AR Reference Case - 5/12/2010																	
Category	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Avoided Costs by costing period																		
Avoided Resource Cost	¢/kWh	3.50	4.14	4.69	5.73	7.41	8.16	8.32	8.38	8.55	8.74	8.93	8.98	8.98	9.06	9.11	9.37	9.60
Avoided Capacity Cost	$/kW-yr	68.29	68.29	68.29	68.29	68.29	68.29	68.29	68.29	68.29	68.29	68.29	68.29	68.29	68.29	68.29	68.29	68.29
	¢/kWh	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24
Avoided Energy Only Cost	¢/kWh	2.25	2.90	3.45	4.49	6.17	6.91	7.07	7.14	7.31	7.50	7.69	7.73	7.74	7.81	7.86	8.13	8.35

A.5. Policy Case Electricity Supply Prices and Avoided Costs

This section presents Synapse's projections of Policy Case electricity supply prices and avoided costs for Arkansas. The projections are outputs from the electricity costing model that Synapse has developed for this project as discussed above. ACEEE provided the Policy Case Load Forecast.

Policy Case Electricity Supply Prices

The Policy Case load forecast, supply forecast, and supply prices are presented in Table A-3. The supply forecast exceeds the load forecast by the level of estimated losses in transmission and distribution. The supply prices include the projected incremental generation costs each year, the retail margin each year and the resulting total average retail rate.

Avoided Electricity Costs

The avoided costs for the policy case are presented in Table A-4. The avoided capacity costs are presented in $/kW-year while avoided electric energy costs are given in ¢/kWh.

Table A-3. Policy Case Load, Supply and Price Forecasts

All costs in constant 2007 dollars.

CASE:	AR Policy Case Revised - 5/26/2010																	
Category	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load Forecast																		
Retail Energy	GWh	47,021	45,915	46,290	46,555	46,352	48,574	48,473	48,421	48,298	48,239	48,217	48,277	48,232	48,171	48,114	48,071	48,030
Retail Demand	MW	8,561	8,360	8,428	8,476	8,439	8,844	8,825	8,816	8,793	8,783	8,779	8,790	8,781	8,770	8,760	8,752	8,745
Supply Forecast																		
Capacity Requirement	MW	11,161	10,898	10,987	11,050	11,002	11,529	11,505	11,493	11,464	11,450	11,445	11,459	11,448	11,434	11,420	11,410	11,400
Capacity Sources																		
In-State Capacity	MW	15,297	15,313	15,842	15,922	16,899	16,909	16,926	16,572	16,218	15,865	15,511	15,138	14,744	14,351	13,957	13,675	13,795
Out-of-State Capacity	MW	-4,136	-4,415	-4,855	-4,872	-5,897	-5,380	-5,420	-5,079	-4,755	-4,415	-4,067	-3,679	-3,296	-2,917	-2,537	-2,265	-2,395
Total Capacity Provided	MW	11,161	10,898	10,987	11,050	11,002	11,529	11,505	11,493	11,464	11,450	11,445	11,459	11,448	11,434	11,420	11,410	11,400
Energy Requirement	GWh	53,304	52,051	52,476	52,777	52,546	55,065	54,950	54,892	54,752	54,685	54,660	54,728	54,678	54,608	54,544	54,495	54,448
Energy Sources																		
In-State Generation	GWh	60,688	59,261	59,745	60,087	59,825	62,693	62,562	62,496	62,337	62,260	62,232	62,309	62,252	62,173	62,099	62,044	61,990
Out-of-State Generation	GWh	-7,384	-7,210	-7,269	-7,311	-7,279	-7,628	-7,612	-7,604	-7,584	-7,575	-7,572	-7,581	-7,574	-7,565	-7,556	-7,549	-7,542
Total Energy Provided	GWh	53,304	52,051	52,476	52,777	52,546	55,065	54,950	54,892	54,752	54,685	54,660	54,728	54,678	54,608	54,544	54,495	54,448
Supply Price Forecast																		
Average Production Cost	¢/kWh	4.67	4.67	4.69	4.78	5.52	5.71	5.83	5.96	6.09	6.24	6.37	6.48	6.56	6.67	6.77	6.91	7.04
Retail Margin	¢/kWh	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02
Average Retail Rate	¢/kWh	6.68	6.69	6.71	6.79	7.54	7.72	7.85	7.98	8.10	8.25	8.39	8.49	8.58	8.69	8.78	8.93	9.06

Table A-4. Policy Case Avoided Costs

All costs in constant 2007 dollars.

CASE:	AR Policy Case Revised - 5/26/2010																	
Category	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Avoided Costs by costing period																		
Avoided Resource Cost	¢/kWh	3.50	4.13	4.68	5.72	7.43	8.23	8.42	8.60	8.77	8.97	9.12	9.18	9.21	9.29	9.34	9.50	9.70
Avoided Capacity Cost	$/kW-yr	68.29	68.29	68.29	68.29	68.29	68.29	68.29	68.29	68.29	68.29	68.29	68.29	68.29	68.29	68.29	68.29	68.29
	¢/kWh	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24
Avoided Energy Only Cost	¢/kWh	2.25	2.89	3.44	4.48	6.19	6.99	7.17	7.35	7.53	7.72	7.87	7.94	7.97	8.05	8.10	8.26	8.45

Appendix B—Energy Efficiency Resource Assessment

B.1. Residential Buildings Sector

B.1.1. Overview of Approach

Our analysis of energy efficiency potential for Arkansas' residential electricity and natural gas sectors considered a scenario with widespread adoption of cost-effective energy efficiency measures during the 18-year period from 2008–2025. We analyzed 18 single family measures for existing residential buildings in Arkansas. These measures are grouped by end-use (heating and cooling loads, water heating, appliances, etc.) and measures for new residential buildings. For each measure, we estimated average measure lifetime, energy savings, and costs per home upon replacement of the product or retrofitting of the measure. For a replacement-on-burnout measure, the cost is the incremental cost of the efficient technology compared to the baseline technology. For retrofit measures, where exiting equipment is not being replaced, such as improved insulation and infiltration reduction, the cost is the full installation cost of the measure.

A measure is determined to be cost-effective if its levelized cost of saved energy (CSE), which discounts the incremental cost of a measure over its lifetime, is less than $0.82/kWh for electricity, or $12.70/MMBtu for natural gas, the current average residential costs in Arkansas (EIA 2008b). Estimated levelized costs for each efficiency measure, which assumes a discount rate of 5%,[54] are shown in Table B-4. Equation 1 shows the calculation for cost of conserved energy.

Equation 1. CSE = PMT ((Discount Rate), (Measure Lifetime), (Measure Cost)) / (Annual Savings per Measure)

Existing Buildings

Existing buildings were analyzed using building modeling software. The software package, TREAT[55], was chosen for its reputation as one of the better residential modeling packages available. It uses a variety of inputs, including house characteristics, appliances, weather data, and occupancy patterns to model the expected energy use of a particular home. It also includes a library of efficiency measures that can be used to model potential efficiency improvements. TREAT was used to establish a baseline as well as model the effects of efficiency improvement measures on the average Arkansas single-family house.

Establishing a Baseline

TREAT uses multiple house characteristics and measures to determine annual energy use. We used approximately 100 inputs to model the baseline average Arkansas home. First, we gathered Arkansas-specific data for each of the inputs. Several local utilities provide detailed housing characteristics data, which covered the majority of the inputs needed. Where there was no data we used RECS data or TREAT defaults to fill in the gaps. In several cases further calculations were needed to determine the inputs. For instance, in the case of furnace and water heater efficiency levels, where only the average age of existing equipment were known, an assumption was made that the minimum federal efficiency would account for the majority of installations. We assume that the federal efficiency level for the years most furnaces and water heaters were installed would be used. Table B-1 gives the data collected for the various TREAT inputs (with multiple values for different percentages of the population, in some cases).

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[54] The 5% discount rate is a real discount rate, which excludes the effects of inflation. A 5% real discount rate is equivalent to an 8-9% nominal discount rate as typically used by utilities in their analyses of cost-effectiveness. Nominal discount rates are typically based on utility cost of capital and include allowance for inflation. Our assumption of a 5% real discount rate applies to our commercial and industrial analyses as well. We use real rates since all of our calculations are in terms of 2007$.
[55] http://www.psdconsulting.com/software/treat

For inputs without values, either the default TREAT value was used, or a value had to be derived (see Table B-2).

Table B-1. Data Collected for TREAT Inputs

Treat Input Categories	Treat Inputs	1st value		2nd value		3rd value	
		Value	% of homes	Value	% of homes	Value	% of homes
General	City						
	Stories	1.2	100%				
	# Bedrooms	3.1	100%				
	# Occupants	2.8	100%				
	Wall color						
	Roof color						
	Foundation type	On piers/raised off ground	48%	Concrete slab	35%	Basement	6%
	If basement, is it heated?	No	80%	Yes	20%		
	Attic	Vented	100%				
	Air leakage	0.30-0.39%	26%	0.40-0.49	26%	0.59+	21%
	Shielding						
Surface Construction	Walls	Brick exterior/masonry veneer <R-19	43% 83%	R-19 to R-30	17%		
	Ceiling	<R-30	63%	R-30 to R-40	38%		
	Ground						
	Foundation—Basement wall	<R-10	6%	>R-20	3%		
	Foundation—Crawl space	No insulation	80%	R-10 to R-20	13%	<R-10	7%
Windows	Glazing	Double pane	86%	Single pane	12%	Storm window	3%
	Frame type						
	Size						
Layout	Ceiling height						
	Shape of the house						
	Dimensions	1000-1500	26%	1501–2000	24%	2001-2500	11%
	Quantity of windows on each wall	(See RECS analysis)					
	Direction house points						
	Space type						
	Is the space cooled?						
	Programmable thermostat?	No	79%	Yes	21%		
	Hours per day occupied	17-24 hrs	38%	9-16 hrs	37%	0-8 hrs	25%
Exterior doors	Quantity of doors on each wall						
	Door type	Wood	60%	Metal	31%	Other	9%
	Size						
	U-Value						
Heating	Heating type	Furnace	74%	Heat pump	21%		
	Heating fuel	Gas	52%	Electric	40%	Other	7%
	Capacity	(See other analysis)					
	Efficiency	(See other analysis)					
	Location						
	Year of heating equipment	(See other analysis)					
	Supply temperature						

Treat Input Categories	Treat Inputs	1st value		2nd value		3rd value	
		Value	% of homes	Value	% of homes	Value	% of homes
Air conditioning	Capacity	(See other analysis)					
	SEER	10	63%	13	30%	12	3%
	Supply temperature						
	Year of cooling equipment	2000–2005	40%	1995–2000	23%		
	Number of units						
	Type of unit	Central	63% 83%	Room	17% 16%	Heat pump Other/none	15% 1%
Fans	Ventilated area		1%				
	Ventilation rate		1%				
	Heat recovery effectiveness		1%				
	Hours/day used		1%				
Hot Water	Type of unit	Boiler	100%				
	Hot water fuel	Gas	50%	Electric	47% 25%	None	3%
	Tank volume	40-49	49%	50-59	30%	80+	14%
	Input	(See other analysis)					
	Supply temperature						
	Additional insulation R-Value						
	Number of units	1	69%	2	31%		
	Solar fraction of water heating						
	Year	2000–2005	50%	1995–2000	25%		
	Thermal efficiency	(See other analysis)					
Hot Water Piping	Insulation R-Value						
	Total area of piping						
	Recirculating system						
	% Piping running through each space						
Hot Water Dema nd	Usage adjustment multiplier						
	Are dishes handwashed						
Lighting	Watts per fixture						
	Hours/day used						
	# of fixtures	0 CFLs	46%	2-5 CFLs	24%	6-10 CFLs	16%
Appliances	Appliance type	Space heater	29%				
	Appliance type	Clothes dryer	90%				
	Fuel type	Electric	78%	Gas	11%	Bottled gas	1%
	Appliance type	Top-loading washer	89%				
	Appliance type	Cooktop/stove/range	99%				
	Fuel type	Electric	64%	Gas	34%		
	Appliance type	Oven	97%				
	Fuel type	Electric	67%	Gas	30%		
	Appliance type	Refrigerator	99% 119%				
	Appliance type	Freezer (standalone)	54%				
	Appliance type	Wine refrigerator	2%				
	Appliance type	Microwave	94%				
	Appliance type	Dishwasher	59%				
	Appliance type	TV	96%				
	Number of units	1	31%	2	31%	3	35%
	Appliance type	VCR/DVD	81%				
	Number of units	1	44%	2	22%	3	15%

Treat Input Categories	Treat Inputs	1st value		2nd value		3rd value	
		Value	% of homes	Value	% of homes	Value	% of homes
Appliances	Appliance type	Stereo	57%				
	Number of units	1	39%	2	13%	3	5%
	Appliance type	Game system	20%				
	Number of units	1	14%	2	4%	3	2%
	Appliance type	PC	53%				
	Number of units	1	42%	2	8%	3	3%
	Appliance type	Fax/scanner	34%				
	Number of units	1	28%	2	5%	3	1%
	Appliance type	Security light	38%				
	Number of units	1	31%	2	5%	3	3%
	Appliance type	Pool pump	7%				

After gathering and/or calculating the data, we determined which values to use in TREAT. Because TREAT models a single home, for inputs that had multiple values (e.g., 78% of homes have electric clothes dryers and 11% have gas) a determination was made which value to use. Wherever possible an average was used. However, for discrete data points (e.g., gas vs. electric), the majority won. This method was used for all inputs except for five. Five inputs that were deemed most critical to baseline energy use, including foundation type, wall construction, heating equipment, heating fuel, and water heater fuel, were selected to have variable inputs. We ran the model 36 times to account for every possible combination of these five inputs, and used a weighted average of the results to calculate the average baseline home. Table B-2 lists the inputs chosen or calculated for the TREAT baseline model.

Table B-2. TREAT Inputs

Treat Input Categories	Treat Inputs	Basecase inputs	
		Input	Reasoning
General	City	Little Rock, AR	City in TREAT database with largest population
	Stories	1	Rounded the average for the region
	# Bedrooms	3	Rounded the average for the region
	# Occupants	3	Rounded the average for the region
	Wall color	Default	
	Roof color	Default	
	Foundation type	VARIABLE	
	If basement, is it heated?	No	Rounded the average for the region
	Attic	Vented	Data shows that all attics are vented
	Air leakage	54.00%	Weighted average from Ozarks data
	Shielding	Default	
Surface Construction	Walls	VARIABLE	
	Ceiling	2x8 fiberglass, R-21 (chose R-23 as closest value)	Weighted average from Ozarks data
	Ground	0.75 wood, 2x10, no insulation, carpet w/ pad	ACEEE estimate (Sachs)
	Foundation—Basement wall	8" block R2; 4" concrete adjacent to ground	ACEEE estimate (Sachs)
	Foundation—Crawl space	chose 4" concrete	Estimate, based on option with lowest R-Value
Windows	Glazing	Double pane, no special coatings	Majority, as found by Ozarks
	Frame type	Wood/vinyl, operable	ACEEE estimate
	Size	Default	
Layout	Ceiling height	Default	
	Shape of the house	Rectangle	ACEEE estimate
	Dimensions	1727 (41.6x41.6)	Weighted average from RECS
	Quantity of windows on each wall	13 total (3,3,3,4)	Weighted average from RECS

Treat Input Categories	Treat Inputs	Basecase inputs	
		Input	Reasoning
	Direction house points	Default	
	Space type	Whole building	
	Is the space cooled?	Yes	Majority
	Programmable thermostat?	No	Majority, as found by Entergy
	Hours per day occupied	13.4	Weighted average from Entergy data
Exterior doors	Quantity of doors on each wall	1	Assume at least 1 door
	Door type	Wood	Majority, as found by Ozarks
	Size	Default	
	U-Value	Arbitrarily selected	
Heating	Heating type	VARIABLE	
	Heating fuel	VARIABLE	
	Capacity	88908	TREAT peak load calculation weighted by ACEEE-estimated safety factor
	Efficiency	78% AFUE	Minimum federal efficiency from average year of purchase
	Location	Put in the vented attic, or basement where applicable	ACEEE estimate
	Year of heating equipment	2001	Average from Entergy data
	Supply temperature	Default	
Air conditioning	Capacity	41728.5	TREAT peak load calculation weighted by ACEEE-estimated safety factor
	SEER	11	Weighted average from Ozarks data
	Supply temperature	Default	
	Year of cooling equipment	2001	Average from Entergy data
	Number of units	1	Assumed
	Type of unit	Central	Majority, as found by Swepco & Entergy
Fans	Ventilated area	0	Majority, as found by Entergy
	Ventilation rate		
	Heat recovery effectiveness		
	Hours/day used		
Hot Water	Type of unit	Boiler	Assumed
	Hot water fuel	VARIABLE	
	Tank volume	54.2	Weighted average from Ozarks data
	Input	40000	Based on a scan of AHRI products
	Supply temperature	Default	
	Additional insulation R-Value	Default	
	Number of units	1	Majority, as found by Ozarks
	Solar fraction of water heating	Default	
	Year	2002	Average from Entergy data
	Thermal efficiency	VARIABLE ALONG WITH FUEL: Gas = 0.52, Electric = 0.88	Minimum federal efficiency from average year of purchase
Hot Water Piping	Insulation R-Value	Default	
	Total area of piping	Default	
	Recirculating system	Default	
	% Piping running through each space	Default	
Hot Water Demand	Usage adjustment multiplier	Default	
	Are dishes handwashed	Default	
Lighting	Watts per fixture	Default	
	Hours/day used	Default	
	# of fixtures	Default	

Treat Input Categories	Treat Inputs	Basecase inputs	
		Input	Reasoning
Appliances	Space heater	Don't include	Majority
	Clothes dryer	Include 1 electric clothes dryer	Majority
	Top-loading washer	Include one top-loading washer	Assumed warm-warm cycle
	Cooktop/stove/range	Include 1 gas range	Assumed no pilot light
	Oven	Include 1 gas oven	Majority
	Refrigerator	Include 1 refrigerator	Arbitrarily chose 20CF, side-by-side, min efficiency
	Freezer (standalone)	Include 1 freezer	Arbitrarily chose 20CF upright min efficiency
	Wine refrigerator	Don't include	Majority
	Microwave	Include 1 microwave	Majority
	Dishwasher	Include 1 dishwasher	Arbitrarily chose 2000 model
	TV	Include 2 TVs	Weighted average from Entergy data
	VCR/DVD	Include 1 VCR/DVD	Weighted average from Entergy data
	Stereo	Don't include, since isn't available in inputs	Weighted average from Entergy data
	Game system	Don't include	Weighted average from Entergy data
	PC	Include 1 PC	Weighted average from Entergy data
	Fax/scanner	Don't include	Weighted average from Entergy data
	Security light	Don't include	Assume included in lighting
	Pool pump	Don't include	Majority

TREAT takes these inputs and gives total home energy use as well as electricity and natural gas consumption by end-use category. All of these outputs were collected for all 36 scenarios, and weighted averages were calculated. Table B-3 gives the average energy use of an Arkansas single family home, per TREAT.

Table B-3. Average Energy Use of a Single Family Arkansas Home

Fuel	End Use	Energy Use		Energy Use in MMBtu
Gas	Heating	305	Therms	30.5
	Hot water	172	Therms	17.2
	Cooking	163	Therms	16.3
Electricity	Heating	3,889	kWh	13.3
	Cooling	3,590	kWh	12.3
	Hot water	2,958	kWh	10.1
	Lighting	1,905	kWh	6.5
	Appliances	5,368	kWh	18.3
Total				**124.5**

Efficiency Potential Analysis

For the analysis of energy efficiency improvement measures, we used TREAT to calculate the savings against the established baseline. Measures were chosen that were applicable to the baseline (e.g., efficient pool pumps were not chosen since pool pumps were not included in the baseline), and were available in the TREAT library of efficiency improvement measures. Cost assumptions and lifetime estimates for each of the measures came from multiple sources.

One of the advantages of using modeling software is that the interaction factors between various measures is automatically calculated. For instance, when lighting is switched from incandescents to CFLs, the cooling load decreases and the heating load increases. These interactions are difficult to account for without the assistance of modeling software. Because TREAT displays both the savings from individual measures and the overall savings of all the measures as a package, this phenomenon can be quantified: in many of the scenarios, the sum of the individual measure savings was roughly double the actual savings of the measures as a package.

We ran these efficiency improvement models on 11 of the variable scenarios, and interpolated to the remainder of the 36 scenarios. The weighted average of the overall savings as well as the individual measure savings were used to compute the residential efficiency potential in Arkansas. Unfortunately the modeling software makes it difficult to determine savings from different fuels, so the savings are simply displayed as MMBtu, and not broken down into different fuel savings potentials.

After determining the weighted average savings, the savings from the individual measures were tuned by applying their percentage savings (out of the sum of the individual savings) to the package savings. In this manner the relative amounts of savings for each measure was preserved, while still accounting for interaction factors by using the modeled package savings figure. For instance, more efficient lighting as an individual measure was seen to save 2 MMBtu/year. However, this was out of a sum of 108 MMBtu for all the individual measures separately. The modeled package of all the savings amounted to only 45 MMBtu. So the 2 MMBtu figure was scaled to the modeled package and resulted in an actual savings of <1 MMBtu.

The next step was to adjust the measure savings by an *Adjustment Factor*. This factor accounts for the technical feasibility of efficiency measures (the percentage of Arkansas homes that satisfy the base case conditions and other technical prerequisites such as heating fuel type) and the current market share of products that already meet the efficiency criteria. These assumptions are made explicit in Table B-4.

We then adjusted replacement measures with lifetimes more than 16 years to only account for the percent turning over in 16 years, which represents the time period of the analysis. Note that the multiplier, *Percent Turnover*, is only applicable to products being replaced upon burnout and not retrofit measures such as insulation. These retrofit measures therefore have 100% of measures "turning over".

Equation 2 shows our calculation for efficiency resource potential, incorporating the 2 factors discussed above.

Equation 2. Efficiency Resource Potential = $\sum$ (Annual Savings per Measure) x (Percent Turnover) x (Adjustment Factor)

To calculate the efficiency resource potential savings by end-use in 2025, we present savings as a percent of end-use energy consumption (assuming current energy consumption by end-use from the baseline TREAT modeling). We then multiply the "% savings" by projected residential energy consumption for that end-use in 2025 to estimate the total savings potential in that year (see Equation 2).

New Construction

We estimate savings from new construction by looking at three levels of efficiency in new homes: 15%, 30%, and 50% better than current energy code. In estimating new home energy savings, we use a similar approach as building codes, which address HVAC and water heating consumption only. We estimated *% applicable* by allocating each home into one of the three bins, with 15% predominating the early years and 50% the later years. See Equation 3 for a summary of how we calculate savings in new construction.

Equation 3. Efficiency Resource Potential in 2025 = (% HVAC & water heating savings per home) x (Percent applicable) x (Projected new HVAC consumption between 2008 and 2005)

Table B-4. Residential Single Family Energy Efficiency Measure Characterizations

Measures	End-use category	Scenario 1 savings (MMBtu)	Adjusted savings (MMBtu)	Cost of Saved energy ($/MMBtu)	% Turnover	Adjustment factor	% End-use savings	Total Savings in 2025 (BBtu)
Insulated ductwork	HVAC Shell	15.5	6.8	$ 2.71	100%	100%	12%	4,627
Infiltration reduction	HVAC Shell	2.0	0.9	$ 11.25	100%	100%	2%	585
Attic insulation	HVAC Shell	4.3	1.9	$ 23.82	100%	100%	3%	1,272
Efficient windows	HVAC Shell	1.9	0.8	$ 29.03	80%	100%	1%	442
HVAC Load-Reducing Measures							*18%*	*6,925*
18 SEER Central AC	HVAC Equipment	5.2	2.3	$ 34.86	89%	100%	4%	1,380
Efficient gas furnace	HVAC Equipment	13.4	5.8	$ 2.93	89%	38%	4%	1,362
Efficient heat pump	HVAC Equipment	22.4	21.4	$ 4.00	89%	40%	13%	5,137
HVAC Equipment Measures							*21%*	*7,879*
Low-flow showerhead	Water Heating	3.9	1.7	$ 1.75	100%	60%	4%	697
Faucet aerator	Water Heating	3.9	1.7	$ 0.53	100%	65%	4%	755
Condensing gas WH	Water Heating	17.1	7.5	$ 10.68	100%	52%	14%	2,631
Efficient electric WH	Water Heating	0.7	0.7	$ 10.33	100%	31%	1%	145
Water Heating Measures							*23%*	*4,227*
CFLs	Lighting	2.1	0.9	$ (3.02)	100%	90%	12%	553
Lighting Measures							*12%*	*553*
Efficient refrigerator	Refrigeration	10.3	4.5	$ 0.63	84%	72%	38%	1,857
Efficient freezer	Refrigeration	0.6	0.3	$ 10.22	84%	49%	2%	77
Refrigeration Measures							*39%*	*1,934*
Efficient clothes washer	Appliances	8.5	3.7	$ 4.56	100%	57%	8%	399
Efficient dishwasher	Appliances	10.3	4.5	$ 0.71	100%	50%	9%	429
Efficient televisions	Appliances	8.6	3.8	$ 2.61	100%	75%	11%	536
1 W Standby	Plug Loads	0.6	0.3	$ -	100%	66%	12%	126
Appliance & Standby Measures							*40%*	*1,491*
New home 15% better than code (Energy Star)		N/A	12.5	$ 4.42	100%	17%	2%	318
New home 30% better than code (Proposed Building Code)		N/A	25.0	$ 3.85	100%	35%	7%	1,297
New home 50% better than code (Tax-credit-eligible)		N/A	41.7	$ 4.33	100%	47%	16%	2,882
New construction							25%	4,496

B.1.4 Residential Sector Measure Descriptions

Duct Insulation

Measure Description: R-8 insulation applied to exposed ductwork in unconditioned spaces.

Data Explanation: Cost ($0.15/sq ft) from DEER Database (CEC 2005). Useful life is 25 years (SWEEP 2002).

Infiltration Reduction

Measure Description: Application of foam and/or caulk around leakage areas applied and tested by a professional using a blower-door.

Data Explanation: Cost ($100) from MT 2004. Useful life of 15 years from SWEEP 2002.

Attic Insulation

Measure Description: Add insulation in attic floor to R-38.

Data Explanation: Incremental cost of $0.32/sq ft from DEER database (CEC 2005). Useful measure life of 20 years from NYSERDA 2003.

Efficient Windows

Measure Description: Window replacements that are double-paned, argon-filled, and e=0.1 on surface 2 or 3.

Data Explanation: Incremental cost of $1.50/sq ft. Number of windows determined by regional RECS data, and size of windows set as TREAT default, resulting in 195 sq ft of fenestration.

Efficient Central AC

Measure Description: 18 SEER Central AC

Data Explanation: Incremental cost of $556 from ENERGY STAR calculator (EPA 2008a) to calculate incremental cost going to a 14.5 SEER. The incremental cost of going from a 14 SEER (the closest value to 14.5 in the DEER database) to 18 SEER was derived from the DEER database (2005) and added on top of the ENERGY STAR incremental cost. The resulting total incremental cost is $926.

Efficient Gas Furnace

Measure Description: AFUE 94%

Data Explanation: Incremental cost ($320) from ENERGY STAR calculator (EPA 2008a). Market share (32%) and measure life (18 years) from Sanchez et al. 2007. Percent applicable (57%) from percentage of single family AR homes with gas heating (Entergy).

Efficient Heat Pump

Measure Description: HSPF 9.

Data Explanation: Incremental cost ($1000) from ENERGY STAR calculator. Measure life (18 years) from Sanchez et al. (2007).

Low-Flow Showerhead

Measure Description: 2.0 gallons per minute (gpm) showerhead.

Data Explanation: Cost estimate ($23) for a low-cost, basic model from the DEER database (CEC 2005). Measure life (10 years) from ACEEE (1994).

Faucet Aerators

Measure Description: 1.5 gallons per minute (gpm) faucet aerator.

Data Explanation: Cost estimate ($7) for a low-cost, basic model from the DEER database (CEC 2005). Measure life (10 years) from ACEEE (1994).

Condensing Gas Water Heater

Measure Description: 54 gallon natural gas storage water heater, 0.86 EF.

Data Explanation: Incremental cost ($750) and measure life (13 years) from Amann et al. (2007). Percent applicable (52%) is the percentage of homes with gas water heaters in Arkansas.

Efficient Electric Water Heater

Measure Description: 54 gallon electric storage water heater, 0.93 EF.

Data Explanation: Incremental cost ($90) from Amann et al. (2007). Measure life (14 years) from NYSERDA (2003). Market share (36%) estimated based on percent of products on the market meeting EF 0.93 in the GAMA product database (GAMA 2007). Percent applicable (48%) is the percentage of homes with electric water heaters in Arkansas.

Compact Fluorescent Lighting

Measure Description: 22W CFL's replacing all baseline lighting.

Data Explanation: Market share (10%) from ACEE estimate based on EPA's estimate of ENERGY STAR lamp sales in 2007 and ACEEE's estimate of total lamp sales. Negative incremental cost is due to the higher initial costs for CFLs being canceled out by the longer lifetime of CFLs.

Efficient Refrigerator

Measure Description: ENERGY STAR 20-CF top-freezer refrigerator.

Data Explanation: Incremental cost ($34) and measure life (19 years) from ACEEE analysis for PG&E/CA Title 24 (PG&E 2007). Market share (28%) from Sanchez et al. (2007) appliance sales data.

Efficient Upright Freezer

Measure Description: ENERGY STAR 20 CF upright automatic-defrost freezer.

Data Explanation: Incremental cost ($34) based on ENERGY STAR incremental cost for refrigerators. Current market share (10%) from Karney (2005). Percent applicable (54%) from Entergy data on penetration of freezers in Arkansas single-family homes.

Efficient Clothes Washer

Measure Description: ENERGY STAR clothes washer

Data Explanation: Incremental cost ($167) from Sanchez et al. (2007). Current market share (36%) from EPA 2007a. Percent applicable (89%) from Entergy data on penetration of clothes washers in Arkansas single-family homes.

Efficient Dishwasher

Measure Description: ENERGY STAR dishwasher

Data Explanation: Incremental cost ($30) from DOE 2007. Market share (15%) from April 2007 LBL analysis on the AHAM-efficiency advocacy agreement. Percent applicable (59%) from Entergy data on penetration of dishwashers in Arkansas single-family homes.

Efficient Televisions

Measure Descriptions: ENERGY STAR televisions.

Data Explanation: Incremental cost ($50) from the incremental cost of 2 televisions ($25 each); ACEEE estimate. Current market share (25%) from ENERGY STAR 2006 appliance sales data.

One-Watt Standby for All Household Electronics

Measure Description: All new electronics devices required to have maximum "off" mode power level of 1 watt.

Data Explanation: New measure consumption (440 kWh) and baseline energy consumption (175 kWh) from ACEEE 2004 Emerging Technologies analysis (Sachs et al. 2004). Current market share (34%) assumed by averaging market shares of all ENERGY STAR home electronics equipment.

ENERGY STAR New Home

Measure Description: New home that uses 15% less energy than code.

Data Explanation: Baseline equals delivered HVAC and water heating energy use per household (across all households). Incremental costs ($805) from personal communication with Shadid (2007). Market share (1.5%) from EPA 2007e. Percent applicable for new homes assumes that 30% and 50% new buildings are phased-in one to two years prior to enactment of codes (30% in 2012 and 50% in 2020).

Advanced Building Code New Home

Measure Description: New home that uses 30% less energy than code.

Data Explanation: Baseline equals delivered HVAC and water heating energy use per household (across all households). Incremental costs ($1480) and market share (0%) from personal communication with Shadid (2007). Percent applicable for new homes assumes that 30% and 50% new buildings are phased-in one to two years prior to enactment of codes (30% in 2012 and 50% in 2020).

ENERGY STAR New Home

Measure Description: New home that uses 50% less energy than code.

Data Explanation: Baseline equals delivered HVAC and water heating energy use per household (across all households). Incremental costs ($2775) and market share (0%) from personal communication with Shadid (2007). Percent applicable for new homes assumes that 30% and 50% new buildings are phased-in one to two years prior to enactment of codes (30% in 2012 and 50% in 2020).

B.2. Commercial Buildings Sector

B.2.1. Electric Analysis

To estimate the resource potential for efficiency in commercial buildings in Arkansas, we first developed a disaggregate characterization of baseline electricity consumption in the state for current electricity use and a reference load forecast (see Table B-5 below). Highly disaggregated commercial electricity consumption data is unfortunately not available at the state level. To estimate these data, we started with current electricity consumption for the Arkansas commercial sector (EIA 2010b) and a forecast out to 2025 based on SERC forecasts, and we disaggregated by end-use using average regional data from CBECS 2003 (EIA 2006) and AEO 2009 (EIA 2009).

Table B-5. Baseline Commercial Electricity Consumption by End-Use (GWh)

End-Use	2009	%	2015	%	2025	%
Heating	400	3%	400	3%	400	3%
Cooling	2,100	18%	2,400	18%	2,800	18%
Ventilation	1,300	11%	1,500	11%	1,700	11%
HVAC subtotal	*3,700*	*32%*	*4,400*	*32%*	*5,000*	*31%*
Water Heating	300	2%	300	2%	300	2%
Refrigeration	1,100	9%	1,300	9%	1,300	8%
Lighting	3,300	28%	3,900	28%	4,200	26%
Office Equipment	800	7%	900	7%	1,200	8%
Other	2,400	21%	2,800	21%	3,900	24%
Total	**11,700**	**100%**	**13,700**	**100%**	**15,800**	**100%**

Next, we estimated commercial square footage in the state using electricity intensity data (kWh per square foot) by census region from CBECS (EIA 2006). We used the West South Central Census Region to estimate overall electricity intensity for the state of Arkansas of 15.3 kWh per square foot. Total electricity consumption in the state divided by the electricity intensity provides an estimate of commercial floorspace. Using this methodology, we estimated 765 million square feet of commercial floorspace in the state.

B.2.1.1 Measure Cost-Effectiveness

We then analyzed 33 efficiency measures for existing commercial buildings and three new construction whole-building measures to examine the cost-effective energy efficiency resource potential. For each efficiency measure, we estimated electricity savings (Annual Savings per Measure) and incremental cost (Measure Cost) in a "replacement on burnout scenario," which assumes that the product is replaced or the measure is installed at the end of the measure's useful life. Savings and costs are incremental to an assumed Baseline Measure. We estimated savings (kWh) and costs ($) on a per-unit and/or a per-square foot commercial floorspace basis. For each measure we also assumed a Measure Lifetime, or the estimated useful life of the product.

A measure is determined to be cost-effective if its levelized cost of saved energy, or cost of conserved energy (CCE), is less than 6.84 cents/kWh, the estimated current average commercial cost of electricity in Arkansas. The estimated CCE for each efficiency measure, which assumes a discount rate of 5%, are shown in the measure descriptions below. Equation 1 shows the calculation for cost of conserved energy.

Our assumed Baseline Measure, Annual Savings per Measure, Measure Cost, Measure Lifetime, and CCE are reported for each of the efficiency measures in the list of measure descriptions below. We group the 33 efficiency measures for existing commercial buildings by end-use and list the 3 new building measures last.

Equation 1. CCE = PMT ((Discount Rate), (Measure Lifetime), (Measure Cost)) / (Annual Savings per Measure (kWh))

B.2.1.2. Total Statewide Resource Potential

For each measure, we derived Annual Savings per Measure on a per square foot basis (kWh per square foot) for the applicable end-use. For measures that we only have savings on a per-unit or per-building basis, we first derive the percent savings and multiply by the Baseline Electricity Intensity for that end-use. The assumed baseline intensities for each end use are shown in Table B-6. As an example, for a specific lighting measure we multiply its percent savings by the baseline electricity intensity (kWh per square foot) for the lighting end-use.

Table B-6. Commercial End-Use Baseline Electricity Intensities (kWh per s.f.)

End Use	kWh	MBtu
Heating	0.5	1.7
Cooling	2.7	9.3
Ventilation	1.7	5.7
Water Heating	0.4	1.2
Cooking	0.1	0.3
Lighting	4.3	14.8
Refrigeration	1.4	4.9
Office Equipment	1.1	3.6
Other	3.1	10.6
HVAC Subtotal	*4.9*	*16.7*
Total	**15.3**	

To estimate the total efficiency resource potential in existing commercial buildings in Arkansas by 2025, we first adjusted the individual measure savings by an Adjustment Factor (See Equation 2). This factor accounts for two adjustments: the technical feasibility of efficiency measures, called the Percent Applicable (the percent of Arkansas floorspace that satisfies the base case conditions and other technical prerequisites such as heating fuel type and cooling equipment, etc); and the Current Market Share, or the percent of products that already meet the efficiency criteria. These assumptions are outlined in each of the efficiency measure descriptions below.

Equation 2. Adjustment Factor = Percent Applicable x (1-Current Market Share)

We then adjusted total savings for interactions among individual measures. For example, we adjusted HVAC equipment savings downward to account for savings already realized through improved building envelope measures (insulation and windows), which reduce heating and cooling loads. Similarly, we adjusted water heating equipment savings to account for reduced water heating loads from the use of more efficient clothes washers. The multiplier for these adjustments is called the Interaction Factor.

Finally, we adjusted replacement measures with lifetimes more than 7 and 17 years to only account for the percent turning over in 7 and 17 years, which represents the benchmark years of 2015 and 2025, respectively. Note that the multiplier, Percent Turnover, is only applicable to products being replaced upon burnout and not retrofit measures such as insulation. These retrofit measures therefore have 100% of measures "turning over."

We then calculated the resource potential for each measure in the state using Equation 3, which takes into account all of the adjustments described above. The sum of the resource potential from all measures is the overall energy efficiency resource potential in the state's commercial buildings sector.

Equation 3. Efficiency Resource Potential in 2015 and 2025 (GWh) = (Annual Savings per Measure (kWh per square foot)) x (Commercial floor space in Arkansas in millions of square feet) x (Percent Applicable) x (Interaction Factor) x (Percent Turnover)

B.2.1.3 Efficiency Measures

Below we present the thirty-six efficiency measures examined for this analysis, grouped by end-use costs, savings (kWh) per product or square foot, *Percent Applicable, Interaction Factor, Percent Turnover,* and total savings potential (GWh) in 2025. Detailed descriptions of each measure are given below, grouped by end-use.

Building Shell Improvements

Cool Roof

Measure Description: This measure involves installing a sun-reflective coating on the roof of a building with a flat top. This reduces air conditioning energy loads by reducing the solar energy absorbed by the roof.

Basecase: The baseline electricity intensity for HVAC end uses in Arkansas (4.9 kWh/ft^2/year) is used as the basecase.

Data Explanation: We assume 4% HVAC load savings (ACEEE 1997) off the baseline electricity intensity for HVAC end-uses in Arkansas (EIA 2006), an incremental cost of $0.25 per ft^2 (SWEEP 2002), and a 20-year average lifetime (SWEEP 2002). Percent applicable (80%) is an ACEEE estimate. Savings and cost per unit are based on a 15,000 ft^2 building (ACEEE 1997). The levelized cost is calculated to be 5.5 cents/kWh.

Roof Insulation

Measure Description: Fiberglass or cellulose insulation material in roof cavities will reduce heat transfer, though the type of building construction limits insulation possibilities. R-values describe the performance factor for insulation levels.

Basecase: The basecase electricity intensity for this measure was disaggregated from the post-savings electricity intensity and the percentage of savings.

Data Explanation: We assume 3% savings and a post-savings electricity intensity of 0.28 kWh/ft^2/year, based on an average of four building types (ACEEE 1997). An average lifetime of 25 years (CL&P 2007) and an incremental cost of 8 cents/ft^2 were also assumed. The measure is shared with gas savings as well, so the portion of the incremental cost attributed to electric savings is 8 cents/sf. The levelized cost is 1.9 cents/kWh.

Double Pane Low-Emissivity Windows

Measure Description: Double-pane windows have insulating air- or gas-filled spaces between each pane, which resist heat flow. Low-emissivity (low-e) glass has a special surface coating to reduce heat transfer back through the window, and a window's R-value represents the amount of heat transfer back through a window. Low-e windows are particularly useful in climates with heavy cooling loads, because they can reflect anywhere from 40% to 70% of the heat that is normally transmitted through clear glass. The Solar Heat Gain Coefficient (SHGC) represents the fraction of solar energy transferred through a window. For example, a low-e window with a 0.4 SHGC keeps out 60% of the sun's heat.

Basecase: The basecase electricity intensity for this measure was disaggregated from the post-savings electricity intensity and the percent savings.

Data Explanation: Percent savings of 3% apply to whole-building electricity consumption (ACEEE 1997). Incremental costs assume $2 per square foot of window (SWEEP 2002). This measure is shared with gas savings as well. A measure life of 25 years is from SWEEP 2002. Percent applicable is an ACEEE estimate. The levelized cost is calculated to be 1.3 cents/kWh.

Heating and Cooling Measures: Equipment and Controls

Duct Testing and Sealing

Measure Description: Testing and sealing air distribution ducts saves energy. This measure assumes supply and return ducts will be fully sealed.

Basecase: The basecase assumes air loss of 29% of fan flow, and leakage of 15% of the system flow.

Data Explanation: Percent savings of 6% apply to whole-building electricity consumption (SWEEP 2002). An incremental cost of $3,375, which assumes $300 per ton, a 10 year lifetime, and 25% applicability are ACEEE estimates. The levelized cost is calculated to be 1.8 cents/kWh.

Primary Air-Handler Fans with Variable-Frequency Drive

Measure Description: Variable Frequency Drive (VFD) controls the speed of a motor by adjusting the frequency of incoming power. By controlling the speed of a motor, the output of the system can be matched to the requirements of the process, thereby improving efficiency.

Basecase: The basecase unit is a 50 hp fan with 60% load factor, 93% efficiency (ODP, EPAct levels) and 3653 operating hours/year (21-50 hp category from ACEEE standards savings analysis).

Data Explanation: We assume 25% savings applies to ventilation only (ACEEE 1997), which is a conservative estimate. We estimate a $6,650 incremental cost, which assumes $125/hp for VFD and $8/hp for a better fan, and a 10-year measure life (SWEEP 2002). ACEEE estimates that this measure can apply to 40% of systems. The levelized cost is calculated to be 3.9 cents/kWh.

High-Efficiency Unitary AC/HP

65,000 Btu–135,000 Btu
135,000 Btu–240,000 Btu

Measure Description: Unitary packaged air conditioners and heat pumps represent the heating, ventilating, and air conditioning (HVAC) equipment class with the greatest energy use in the commercial sector in the United States, and are used in approximately 48% of the cooled floor space in the commercial sector (DOE 2004). High efficiency units have a greater energy efficiency ratio (EER).

Basecase: The assumed basecase unit meets the 2010 federal efficiency standard. Baseline electricity intensity for this end-use, 4.9 kWh per ft^2, is the estimated HVAC consumption in commercial buildings in Arkansas. This is data from the West South Central census division from EIA's commercial buildings survey (EIA 2006).

Data Explanation: This measure includes two size ranges; the first is 65,000 Btu to 135,000 Btu, and the second is 135,000 Btu to 240,000 Btu. The measure assumes a 12 EER unit relative to the 2010 federal standard, which ranges from about 10.4 EER to 11.2 EER, depending on the unit type and size. The energy savings average 1,070 kWh (7.2%) for the smaller unit and 3,371 kWh (10.8%) for the larger unit. We assume a measure lifetime of 15 years (LBNL 2003). Incremental costs (average $629 for 65 kBtu to135 kBtu and $1,415 for 135 kBtu to 240 kBtu) are derived from DOE's Technical Support Document (DOE 2004). Percent applicable (33% for 65 kBtu to 135 kBtu and 15% for 135 kBtu to 240 kBtu), and the percent of floorspace with cooling from unitary equipment are also from DOE's Technical Support Document (DOE 2004). The levelized cost is calculated to be 4–5.7 cents/kWh, depending on unit type and size.

High-Efficiency Packaged Terminal AC/HP

Measure Description: PTACs and PTHPs are self-contained heating and air-conditioning units encased inside a sleeve specifically designed to go through the exterior building wall. The basic design of a PTAC is comprised of a compressor, an evaporator, a condenser, a fan, and an enclosure. They are primarily used to provide space conditioning for commercial facilities such as hotels, hospitals, apartments, dormitories, schools, and offices. High-efficiency units have a higher energy efficiency ratio (EER) for cooling units and coefficient of performance (COP) for heat pumps.

Basecase: Consistent with all HVAC-related measures, the baseline electricity intensity is 4.9 kWh per ft^2, which is the estimated HVAC consumption in commercial buildings in Arkansas. This is based on the Mid Atlantic region from EIA's commercial buildings survey (EIA 2006).

Data Explanation: We assume that high efficiency units save an average of 7.8%, or 226 kWh per unit, relative to a basecase, which is based on an ACEEE submission to ASHRAE using web data. The measure life is 15 years (ANSI/ASHRAE 1999). Percent applicable is 5%, which is the percent of cooling floorspace from packaged terminal units (ADL 2001). The levelized cost is calculated to be 3.8 cents/kWh.

Efficient Room Air Conditioner

Measure Description: An ENERGY STAR room AC must be at least a 10% improvement over the 2000 federal standard (an average 8000 Btu unit must have a 10.8 EER).

Basecase: The assumed basecase unit is a room A/C that meets 2000 federal energy standards (an average 8000 Btu unit has a 9.8 EER) and uses an average of 677 kWh per unit. Baseline electricity intensity for this end-use, 2.7 kWh per ft^2, is the estimated cooling consumption in commercial buildings in Arkansas. This is based on the West South Central census division from EIA's commercial buildings survey (EIA 2006).

Data Explanation: We assume an ENERGY STAR room AC uses 590 kWh per year, saves 13% of basecase energy, and has an incremental cost of $35 (ENERGY STAR calculator). We assume a measure life of 13 years (ENERGY STAR calculator), a current market share of 52% (EPA 2007a), and percent applicable assumes 8% of cooling floorspace uses room AC units (ADL 2001). The levelized cost is calculated to be 4.3 cents/kWh.

High-Efficiency Chiller

Measure Description: "Chillers" are the hearts of very large air-conditioning systems for buildings and campuses with central chilled water systems. A centrifugal chiller utilizes the vapor compression cycle to chill water and reject the heat collected from the chilled water plus the heat from the compressor to a second water loop controlled by a cooling tower.

Basecase: The basecase unit assumes 0.634 kW/ton T24 from DEER for an average 150 ton system and 1,593 national average full-load operating hours from the ASHRAE 90.1-1999 analysis. Baseline electricity intensity for this end-use, 4.9 kWh per ft^2, is the estimated HVAC consumption in commercial buildings in Arkansas. This is based on the West South Central census division from EIA's commercial buildings survey (EIA 2006).

Data Explanation: We assume the new measure has 20% savings, which is derived from estimates provided in SWEEP (2002) and ACEEE (1997). The lifetime estimate of 23 years is from the ASHRAE Handbook (ASHRAE 2007). Incremental costs are $9,900 and assume a 150 ton average unit (CEC 2005). Percent applicable (33%) assumes percentage of cooling floorspace using chillers (ADL 2001). The levelized cost is calculated to be 2.4 cents/kWh.

Dual-Enthalpy Economizer

Measure Description: Economizers modulate the amount of outside air introduced into the ventilation system based on the relative temperature and humidity of the outside and return air. If the enthalpy, or the latent and sensible heat, of the outside air is less than that of the return air when space cooling is required, then the outside air is allowed to reduce or eliminate the cooling requirement of the AC equipment.

Basecase: Baseline electricity intensity, 4.9 kWh per ft^2, is the estimated HVAC consumption in commercial buildings in Arkansas. This is based on the West South Central census division from EIA's commercial buildings survey (EIA 2006).

Data Explanation: Savings per unit assume 276 kWh (20% savings) per ton for an average 11-ton unit (CL&P 2007). Average measure life is 10 years (CL&P 2007). Incremental costs per unit are from NYSERDA 2003. Percent applicable is the portion of cooling square footage represented by packaged AC and HP units, and assumes that 90% of these unitary systems could benefit from economizers (ACEEE estimate). It also assumes a 5% current market share (ACEEE estimate). The levelized cost is calculated to be 3.8 cents/kWh.

Demand-Controlled Ventilation

Measure Description: Often, HVAC systems are designed to supply ventilated air based on assumed occupancy levels, resulting in over-ventilation. Demand-controlled ventilation monitors CO_2 levels in different zones and delivers the required ventilation only when and where it is needed.

Basecase: The basecase is standard ventilation electricity consumption for a 50,000 ft^2 office building, or about 40,000 kWh/year (Sachs et al. 2004). Baseline electricity intensity for this end-use, 1.7 kWh per ft^2, is the estimated ventilation consumption in commercial buildings in Arkansas. This is based on the West South Central census division from EIA's commercial buildings survey (EIA 2006).

Data Explanation: We assume 20% savings for this measure (Sachs et al. 2004). Energy use per unit is 32,000 kWh/year, assuming a 50,000 ft^2 building (Sachs et al. 2004). The lifetime estimate is 15 years, and incremental costs are $3,450 (Sachs et al. 2004). The measure is applicable to 90% of larger (60%) cooling units (Sachs et al. 2004). The levelized cost is calculated to be 3.8 cents/kWh.

HVAC Tune-Up

Measure Description: Most HVAC technicians lack interest, training, equipment and methods to perform quality refrigerant charge and airflow (RCA) tune-ups. Because many new and existing air conditioners have improper RCA, which reduces efficiency, there is significant potential for energy savings by diagnosing and correcting RCA.

Basecase: The assumed basecase unit is a 4.5 ton commercial unitary AC/HP per California program experience (CPUC 2006), estimated to use 8,396 annual kWh per the unitary AC/HP measure. The base electricity intensity for the HVAC end-use is 4.9 kWh/ ft^2, the average for small buildings less than 25,000 ft^2, for which this measure is applicable.

Data Explanation: We assume 11% savings from this measure according to California's DEER database (CEC 2005) and the California Refrigerant and Air Charge (RCA) program report (CPUC 2006). We assume that 60% of units have improper RCA (CPUC 2006), and therefore this measure is applicable to 60% of unitary HVAC units in buildings less than or equal to 25,000 ft^2 (EIA 2006; average of south and mid-Atlantic regions). We estimate an average measure life of 3 years, as units need to be periodically re-tuned. We assume a cost of $158 for this measure, based on a $35/ton labor cost (CEC 2005) and an assumed 4.5-ton unit. The levelized cost is calculated to be 6.3 cents/kWh.

Retrocommissioning

Measure Description: Commercial building performance tends to degrade over time, and many new buildings do not perform as designed, requiring periodic upgrades to restore system functions to optimal performance. Retrocommissioning (RCx) is a systematic process to optimize building performance through O&M tune-up activities and diagnostic testing to identify problems in mechanical systems, controls, and lighting. The best candidates for RCx are buildings over 50,000 or 100,000 ft2.

Basecase: The baseline is electricity intensity for HVAC and lighting end-uses in buildings greater than 50,000 ft2 (10 kWh/ ft2), which is based on data from CBECS (EIA 2006). We take the average of the West South Central census division to estimate electricity intensity in Arkansas buildings.

Data Explanation: We assume 10% savings for HVAC and lighting end-uses (Sachs et al. 2004) in all commercial floorspace for buildings greater than 100,000 ft2, and 50% of floorspace in buildings 50,000 ft2 or greater based on data from CBECS (EIA 2006). Xcel Energy's RCx program results estimate an average RCx useful life of 7 years (Xcel Energy 2006). We assume a $0.14 cost per ft2 (Sachs et al. 2004). The cost is shared with gas savings from the same measure, so the actual cost for electric savings is $0.14. The levelized cost is calculated to be 2.7 cents/kWh.

Water Heating Measures

Heat Pump Water Heater

Measure Description: A heat pump water heater uses electricity to move heat from one place to another, rather than a less efficient electric resistance water heater which uses electricity to generate the heat directly. The heat source is the outside air or air in the basement where the unit is located.

Basecase: The basecase is standard electric water heating, with electricity consumption of 28,310 kWh/year (derived from energy savings and percent savings). Baseline electricity intensity for this end-use, 0.36 kWh per ft^2, is the estimated water heating consumption in commercial buildings in Arkansas. This is based on the West South Central region from EIA's commercial buildings survey.

Data Explanation: We assumed a 50% savings, based on a simple coefficient of performance ratio. The assumed 14,155 kWh savings, $4,067 incremental cost, and 12 year lifetime estimates are from NYSERDA 2003. Percent applicable is based on engineering estimates for NYSERDA 2003, which assumes the measure is applicable to 70% of food service floorspace and 30% of lodging, education, and health care floorspace. Percent applicable is then multiplied by 2, since these building types are more energy and hot-water intensive than the average commercial building. The levelized cost is calculated to be 3.2 cents/kWh.

Efficient Commercial Clothes Washer (Water Heating Portion)

Measure Description: A high-efficiency commercial clothes washer saves both energy and water, and as a result reduces water heating loads. For a high-efficiency clothes washer, we assume a unit with an MEF of 2.0, which represents about 80% of products on ENERGY STAR's product lists.

Basecase: The basecase unit is a clothes washer that meets DOE's federal efficiency standard of 1.26 MEF. An average unit consumes 1,136 kWh annually for water heating, which is derived from DOE 2007. Baseline electricity intensity for this end-use is 0.36 kWh/ft^2/year (water heating portion only).

Data Explanation: Savings on electric water heating from this measure assume a 2.0 MEF clothes washer uses an average 431 kWh annually, for a 62% savings, which is derived from DOE's TSD (DOE 2007). We assume the measure is applicable to the 17% of units that have electric water heating, and assume a 20% market share of efficient products. The overall stock estimate is based on national stock data (DOE 2007) and prorated to Arkansas based on commercial building floorspace. We assume an incremental cost for an efficient unit is $316 and an 11-year measure life (DOE 2007). The levelized cost is calculated to be 3.7 cents/kWh.

Refrigeration Measures

Efficient Walk-In Refrigerators & Freezers

Measure Description: Walk-in refrigerators and freezers (walk-ins) are medium and low-temperature refrigerated spaces that can be walked into, and that are used to maintain the temperature of pre-cooled materials (not to rapidly cool down materials from warmer temperatures). A high-efficiency walk-in is defined as meeting the 2004 CEC standard for walk-ins. This includes prescriptive requirements such as higher levels of insulation, motor types, and the use of automatic door-closers (Nadel et al. 2006).

Basecase: The baseline energy use for an average walk-in is 18,859 kWh/year (Nadel et al. 2006). Baseline electricity intensity for this end-use, 1.43 kWh per ft^2, is the estimated refrigeration energy consumption in commercial buildings in Arkansas. This is based on the West South Central division from EIA's commercial buildings survey.

Data Explanation: For a high-efficiency walk-in unit, we assume 44% savings over a baseline unit, or 8220 kWh/year, $957 incremental cost, and a 12 year measure lifetime (Nadel et al. 2006), which are based on PG&E 2008. We estimate percent applicable as the 18% of refrigeration energy use attributed to walk-ins (ADL 1996) and estimate a 50% current market share of high-efficiency products (ACEEE estimate). The levelized cost is calculated to be 1.3 cents/kWh.

Efficient Reach-In Coolers & Freezers

Measure Description: This measure includes high-efficiency packaged commercial reach-in refrigerators and freezers with solid doors, and refrigerators with transparent doors such as beverage merchandisers. High-efficiency units are those that meet the CEE Tier 2 performance standard, as estimated in PG&E 2005.

Basecase: We assume a baseline unit, which is one that meets that upcoming (2009 or 2010) federal standard, uses 4,027 kWh per year. This is weighted by sales of unit type per PG&E 2004. Baseline electricity intensity for this end-use, 1.43 kWh per ft^2, is the estimated refrigeration energy consumption in commercial buildings in Arkansas. This is based on the West South Central division from EIA's commercial buildings survey.

Data Explanation: The savings estimate for a high-efficiency unit, 31% savings or 1,268 kWh per year, is a weighted average of different types of reach-ins that meet CEE's Tier 2 performance standard (PG&E 2004a). We estimate an average lifetime of 9 years and an incremental cost of $177, both per PG&E 2004a. We estimate percent applicable as the percent of refrigeration energy use attributed to reach-ins and beverage merchandisers, or 17% (ADL 1996), and assume a 10% current market share of high-efficiency products per PG&E 2004a. The levelized cost is calculated to be 2.0 cents/kWh.

Efficient Ice-Maker

Measure Description: Commercial ice makers, which are used in hospitals, hotels, and food service and preservation, have energy savings potential largely in their refrigeration systems. We assume an efficient icemaker meets CEC's Tier 2 level of energy savings, which incorporate improved compressors, heat exchangers, and controls, as well as better insulation and gaskets.

Basecase: The baseline energy use, 3,338 kWh per year, is a weighted average of different types of ice-makers that meet the 2010 standard. Baseline electricity intensity for this end-use, 1.43 kWh per ft^2, is the estimated refrigeration energy consumption in commercial buildings in Arkansas. This is based on the Mid Atlantic region from EIA's commercial buildings survey.

Data Explanation: The 16% savings estimate for a high-efficiency unit, or 542 kWh per year, is a weighted average of different types of ice-makers that meet CEC's tier 2 energy savings (PG&E 2004a. We estimate an average lifetime of 10 years and an incremental cost of $100, both per PG&E 2005. We estimate percent applicable as the percent of refrigeration energy use attributed to ice-makers, or 10% (ACEEE Estimate), and assume a 10% current market share of high-efficiency products per PG&E (2004a) and ACEEE judgment. The levelized cost is calculated to be 2.4 cents/kWh.

Efficient Built-Up Refrigeration System

Measure Description: Built-up or supermarket refrigeration systems are primarily made up of refrigerated display cases for holding food for self-service shopping, as well as machine room cooling technologies. More efficient built-up systems include improved machine room technologies (evaporative condensers, mechanical sub-cooling, and heat reclaim), high-efficiency evaporative fan motors, hot gas defrost, liquid-suction heat exchangers, antisweat control, and defrost control.

Basecase: The measure baseline is 1,600,000 kWh for a 45,000 ft^2 supermarket with a built-up refrigeration system. Baseline electricity intensity for this end-use, 1.43 kWh per ft^2, is the estimated refrigeration energy consumption in commercial buildings in Arkansas. This is based on the West South Central division from EIA's commercial buildings survey.

Data Explanation: Per-unit savings of 336,000 kWh (21%) are from ADL 1996 and assume an average new 45,000 ft^2 supermarket with a 5-year payback. We estimate percent applicable as the percent of refrigeration energy use attributed to built-up refrigeration, or 33% (ADL 1996). Incremental cost ($37,000) and lifetime (10 years) are from ADL 1996. The levelized cost is calculated to be 1.4 cents/kWh.

Efficient Vending Machine

Measure Description: ENERGY STAR vending machines must consume 50% less energy than standard machines. Under the Tier II ENERGY STAR level, this translates to a maximum energy consumption of 6.53 kWh/day for a 650-can machine.

Basecase: A Tier I ENERGY STAR level vending machine is assumed to be the basecase. On average, it uses 2,816 kWh per year (ENERGY STAR calculator for a 600 can machine). Baseline electricity intensity for this end-use, 1.43 kWh per ft^2, is the estimated refrigeration energy consumption in commercial buildings in Arkansas. This is based on the West South Central division from EIA's commercial buildings survey.

Data Explanation: Per unit savings of 18% (507 kWh/year) are estimated from ASAP 2007 based on ENERGY STAR calculator estimates. Likewise, an incremental cost of $30, and a lifetime estimate of 10 years are from ASAP 2007. We estimate percent applicable as the percent of refrigeration energy use attributed to built-up refrigeration, or 13% (NYSERDA 2003). The levelized cost is calculated to be 0.8 cents/kWh.

Vending Miser

Measure Description: A Vending Miser is an energy control device for refrigerated vending machines. Using an occupancy sensor, the control turns off the machine's lights and duty cycles the compressor based on ambient air temperature.

Basecase: The basecase unit is an efficient vending machine that meets the ENERGY STAR tier II level and uses 2,309 kWh per year (ENERGY STAR calculator for a 600 can machine). Baseline electricity intensity is for the refrigeration end-use (1.43 kWh/ ft^2).

Data Explanation: We assume 35% savings for this measure based on manufacturer data (USA Technologies 2008), an incremental cost of $167 (NYSERDA 2003), and a measure life of 10 years (NYSERDA 2003). The levelized cost is calculated to be 2.7 cents/kWh.

Appliances

Efficient Hot Food Holding Cabinets

Measure Description: Commercial hot food holding cabinets are used in the commercial kitchen industry primarily for keeping food at safe serving temperature, without drying it out or further cooking it. These cabinets can also be used to keep plates warm and to transport food for catering events. High efficiency models differ mainly in that they are better insulated.

Basecase: The basecase unit is an uninsulated cabinet that consumes 5,190 kWh per year. This was calculated from PG&E 2004b using a simple average of three sizes of cabinets, and then weighting the average using CASE figures for insulated cabinets.

Data Explanation: The energy savings from an insulated holding cabinet are 1,815 kWh per year (35% savings), with an incremental cost of $453, and an estimated 15 year lifetime (Neubauer et al. 2009). Percent applicable refers to the 25% of holding cabinets that are currently uninsulated (Neubauer et al. 2009). The levelized cost is calculated to be 2.4 cents/kWh.

Efficient Commercial Clothes Washer (excluding hot water energy)

Measure Description: A high-efficiency commercial clothes washer saves both energy and water. For a high-efficiency clothes washer, we assume a unit with an MEF of 2.0, which represent about 80% of products on ENERGY STAR's product lists.

Basecase: The basecase unit is a clothes washer that meets DOE's federal efficiency standard of 1.26 MEF. An average unit consumes 1,530 kWh annually for non-water heating uses, which is derived from DOE 2007.

Data Explanation: Electric savings from this measure assume a 2.0 MEF clothes washer uses an average 1,191 kWh annually, for a 22% savings, which is derived from DOE's TSD (DOE 2007). We assume the measure is applicable to the 37% of units that have electric dryer heating (removal of moisture from clothes), and assume a 20% market share of efficient products. The overall stock estimate is based on national stock data (DOE 2007) and prorated to Arkansas based on commercial building floorspace. We assume an incremental cost for an efficient unit is $316 and an 11-year measure life (DOE 2007). The levelized cost is calculated to be 3.7 cents/kWh.

Lighting Measures

Fluorescent Lighting Improvements

Measure Description: The new measure assumes extra-efficient ballasts and high-lumen lamps are installed with the ballast factor of new ballasts chosen to provide the right amount of light for an application.

Basecase: Basecase watts per square foot reflects current installed fixtures. This includes 84,000 kWh used annually for fluorescent lighting per average 14,000 ft^2 commercial building (Navigant 2002). On average, fluorescent lights are operated 9.7 hours/day. We assume 2-lamp standard T8 fixtures and electronic ballasts as the baseline, plus a small number of existing 3-lamp T12 fixtures with magnetic ballasts that are not likely to be replaced in the absence of programs over the time horizon.

Data Explanation: We assume a percent savings of 27%. The incremental costs are $2 extra per ballast, and $1 extra for each of 2 lamps. The percent applicable (56%) is the fluorescent percent of total commercial lighting kWh (Navigant 2002). The levelized cost is calculated to be 0.7 cents/kWh.

HID Lighting Improvements

Measure Description: Metal halide lamps produce light by passing an electric arc through a mixture of gases. Efficiency improvements in metal halide lamps include pulse start lamp technology, electronic ballasts, and improved fixtures.

Basecase: Same basecase as #27 (Fluorescent lighting improvements).

Data Explanation: The new measure savings and costs are from a PG&E CASE study on Metal Halide Lamps & Fixtures (PG&E 2004c). Energy savings were 447 kWh per year (26%), and incremental costs were $60. Percent applicable (12%) is the percentage of commercial electricity use for lighting that comes from HIDs (Navigant 2002). The levelized cost is calculated to be 6.3 cents/kWh.

Replace Incandescent Lamps with CFLs

Measure Description: We assume that 32% of lighting in the commercial sector is incandescent (Navigant 2002). The new measure assumes that 70% of current incandescents are replaced with CFLs. We estimate 75% of these will shift to CFLs as a result of Federal standards while 20% will use HIR lamps instead but could be switched to CFLs. These lights represent area and general lighting.

Basecase: The basecase is 2 kWh/sf annually. This represents the amount of energy used for incandescent lighting in the average commercial building, and is derived from the average number of lamps, the average lamp wattage, and the average annual operating time (Navigant 2002).

Data Explanation: Energy savings are 1.5 kWh per sf annually, or 72%. This equates to annual per unit savings of 138 kWh. Incremental costs include $10 in the cost of a CFL, but save $32 in labor for replacing the bulb, so the result is a cost savings. ACEEE estimates that 70% of sockets are applicable for the new measure. The levelized cost is calculated to be a net savings of 1 cent/kWh.

Replace Incandescent Lamps with LEDs

Measure Description: The new measure assumes that 20% of current incandescents (10% low-wattage and 10% miscellaneous) are used for display lighting, and can be replaced with LED lights.

Basecase: The basecase is 0.23 kWh/sf annually. This is derived from the average wattage of quartz halogen, low-wattage, and average incandescents; the average number of each type of bulb in a commercial building; and the average annual operating time (Navigant 2002).

Data Explanation: Energy savings are 0.2 kWh per sf annually, or 88%, assuming LED replacement wattages as indicated by Navigant 2008. Incremental costs include $0.05 per sf, a weighted average of the costs of each bulb, and including a $32 labor savings for replacing each bulb. The LED prices were calculated using average efficacy and $/klm projections for 2010 (Navigant 2008). Percent applicable assumes that 100% of these specific bulbs are replaceable (Navigant 2008). Between this measure and the previous measure (replacing incandescents with CFLs), 90% of incandescents are assumed to be replaceable, allowing 10% of incandescents (for specialty applications) to remain. The levelized cost is calculated to be 3.7 cents/kWh.

Occupancy Sensor for Lighting

Measure Description: Installation of occupancy sensors can greatly reduce lighting energy demands in commercial spaces, by automatically turning off lights in unoccupied spaces.

Basecase: Same basecase as #27 (Fluorescent lighting improvements).

Data Explanation: Energy savings of 361 kWh per year (NYSERDA 2003) assumes 30% energy reduction in individual offices and rooms and 7.5% reduction in open spaces (ACEEE estimate). Incremental cost ($48) and lifetime (10 years) estimates are from NYSERDA 2003. Percent applicable (38%) is from Sachs et al. (2004). The levelized cost is calculated to be 1.7 cents/kWh.

Daylight Dimming System

Measure Description: A daylight dimming system automatically dims electric lights to take advantage (or "harvest") natural daylight.

Basecase: Same basecase as #27 (Fluorescent lighting improvements).

Data Explanation: Energy savings are estimated to be 143 kWh per year, or 35% (NYSERDA 2003). Savings apply for lamps on the perimeters of buildings (25% applicable—PIER 2003). Incremental cost ($68) and lifetime (20 years) estimates are from NYSERDA 2003. The levelized cost is calculated to be 3.8 cents/kWh.

Outdoor Lighting—Controls

Measure Description: This measure includes a variety of lighting control technologies for exterior lights.

Basecase: No basecase data was available for this measure.

Data Explanation: We assume a savings of 174 kWh, or 20%, from lighting controls. Incremental costs of $43 are from DEER 2001 and assume each control on average controls three fixtures. Percent applicable of 30% is an ACEEE estimate. The levelized cost is calculated to be 2.5 cents/kWh.

Miscellaneous

Office Equipment

Measure Description: This measure assumes a high-efficiency fax, printer, computer display, internal power supply, and a low mass copier.

Basecase: Baseline electricity use is 2886 kWh per year (NYSERDA 2003). Baseline electricity intensity for this end-use, 1.1 kWh per ft^2, is the estimated office equipment energy consumption in commercial buildings in Arkansas. This is based on the West South Central Division from EIA's commercial buildings survey.

Data Explanation: Energy savings were 1410 kWh per year (49%), lifetime was 5 years, and incremental costs were $20. Percent applicable is estimated to be (50%) (NYSERDA 2003). The levelized cost is calculated to be 0.3 cents/kWh.

Turn Off Office Equipment After Hours

Measure Description: This measure involves turning off, or putting into a low-power state: vending machines, computers, monitors, printers and copiers.

Basecase: Baseline electricity use is 1.1 kWh/ft2, based on data from CBECS, LBNL, and ENERGY STAR.

Data Explanation: Energy savings were 6763 kWh per year (40%), lifetime was 20 years, and incremental costs were $0. Percent applicable is 100%, as data for the savings already took into account the number of buildings that already shut down equipment after hours. The levelized cost is $0/kWh

New Buildings

Efficient New Building (15% Savings)

Measure Description: Incorporating energy efficiency into building design is best achieved at the time of construction. New buildings can achieve major energy savings in heating and cooling, as well as energy-saving appliances.

Basecase: Basecase of 7 kWh per ft^2 is an estimate of HVAC, water heating, and lighting end-use electricity intensity for new buildings in Arkansas, derived from data for buildings built from 2000–2003 (EIA 2006).

Data Explanation: Incremental cost of $0.35 per ft^2 and measure life of 17 years are from NGRID 2007. The cost is shared with gas savings from the same measure, so the actual cost for electric savings is $0.24. Percent applicable of 18% for this new buildings measure assume that 30% and 50% new buildings savings are phased in one to two years prior to enactment of codes in the policy scenarios (30% in 2012 and 50% in 2020). The levelized cost is calculated to be 1.6 cents/kWh.

Efficient New Building (30% Savings)

Measure Description: Incorporating energy efficiency into building design is best achieved at the time of construction. New buildings can achieve major energy savings in heating and cooling, as well as energy-saving appliances.

Basecase: Basecase of 7 kWh per ft^2 is an estimate of HVAC, water heating, and lighting end-use electricity intensity for new VA buildings, derived from data for buildings built from 2000–2003 (EIA 2006).

Data Explanation: In New York, estimates show that commercial buildings can reach 30% beyond code at an investment of $0.70/kWh. To be conservative, we estimate $0.70/kWh by doubling the costs of a 15%-beyond-code building. The cost is shared with gas savings from the same measure, so the actual cost for electric savings is $0.47. Measure life of 17 years is from NGRID 2007. Percent applicable of 35% for 30% savings new buildings assume that 30% and 50% new buildings savings are phased in one to two years prior to enactment of codes in the policy scenarios (30% in 2012 and 50% in 2020). The levelized cost is calculated to be 1.6 cents/kWh.

Tax-Credit Eligible Building (50% Savings)

Measure Description: A federal tax incentive is available for new buildings that are constructed to save at least 50% of the heating, cooling, ventilation, water heating, and interior lighting cost of a building that meets ASHRAE standard 90.1-2001.

Basecase: Basecase of 7 kWh per ft^2 is an estimate of HVAC, water heating, and lighting end-use electricity intensity for new buildings in Arkansas, derived from data for buildings built from 2000–2003 (EIA 2006).

Data Explanation: Incremental costs of $0.66 per ft2 are derived from NREL (2008) studies on energy savings for medium box retail stores and supermarkets. This cost is shared with gas savings from the same measure, so the actual cost for electric savings is $0.44. Percent applicable is 18%, accounting only for the share of buildings that call into the two types of buildings covered in the NREL studies. Measure life of 17 years is from NGRID 2007. The levelized cost is calculated to be 0.9 cents/kWh.

Table B-7. Commercial Building Electricity Measure Characterizations

Measures	Measure Life (Years)	Annual kWh svgs per unit	2007 Arkansas Stock	kWh svgs per s.f.	Incremental cost per unit	Incremental cost per s.f.	Cost of Conserved Energy (2007$/kWh saved)	Adjustment Factor	% Turnover	Interaction Factor	Savings in 2025 (GWh)
Existing Buildings											
Building Shell											
Cool roof	20	5,500	NA	0.18	$ 3,750	$ 0.25	$ 0.05	80%	85%	100%	94
Roof insulation	25	NA	NA	0.28	NA	$ 0.08	$ 0.02	35%	100%	100%	74
Low-e windows	25	NA	NA	0.26	NA	$ 0.05	$ 0.01	75%	68%	100%	103
											272
HVAC											
Duct testing and sealing	10	24,830	NA	0.53	$ 3,380	NA	$ 0.02	25%	100%	100%	102
Efficient ventilation fans & motors w VFD	10	22,000	NA	0.42	$ 6,650	NA	$ 0.04	40%	100%	92%	117
HVAC Load-Reducing Measures Subtotal											**219**
High-effic. unitary AC & HP (65-135 kBtu)	15	1,100	NA	0.35	$ 630	NA	$ 0.06	33%	100%	92%	82
High-effic. unitary AC & HP (135-240 kBtu)	15	3,400	NA	0.53	$ 1,420	NA	$ 0.04	15%	100%	92%	55
Packaged Terminal HP and AC	15	230	NA	0.38	$ 90	NA	$ 0.04	5%	100%	92%	13
Efficient room air conditioner	13	90	NA	0.35	$ 40	NA	$ 0.04	4%	100%	92%	9
High-efficiency chiller system	23	30,350	NA	0.98	$ 9,900	NA	$ 0.02	33%	74%	92%	168
HVAC Equipment Measures Subtotal											**328**
Dual Enthalpy Control	10	3,040	NA	0.55	$ 890	NA	$ 0.04	46%	100%	82%	159
Demand-Controlled Ventilation	15	8,000	NA	0.33	$ 3,450	NA	$ 0.04	54%	100%	82%	113
HVAC tuneup (smaller buildings)	3	920	NA	0.54	$ 160	NA	$ 0.06	22%	100%	82%	75
Retrocommissioning	7	NA	NA	0.91	NA	$ 0.10	$ 0.03	32%	100%	82%	186
HVAC Control Measures Subtotal											**533**
HVAC Subtotal											**1,080**
Water Heating											
Commercial clothes washers	11	700	23,400	0.00	$ 320	NA	$ 0.04	14%	100%	100%	2
Heat pump water heater	12	14,160	NA	0.18	$ 4,070	NA	$ 0.03	16%	100%	99%	22
											24
Refrigeration											
Walk-in coolers & freezers	12	8,200		0.62	$ 960	NA	$ 0.01	9%	100%	100%	43
Reach-in coolers & freezers	9	1,270		0.45	$ 180	NA	$ 0.02	15%	100%	100%	53
Ice-makers	10	540		0.23	$ 100	NA	$ 0.02	9%	100%	100%	16
Supermarket (built-up) refrigeration system	10	336,000		0.30	$ 37,000	NA	$ 0.01	33%	100%	100%	75
Vending machines (to tier 2 ENERGY STAR level)	10	500		0.26	$ 30	NA	$ 0.01	13%	100%	100%	27

Vending miser	10	810		0.41	$ 170	NA	$ 0.03	13%	100%	100%	42
											257
Lighting											
Fluorescent lighting improvements	13	60	-	1.18	$ 5	NA	$ 0.01	56%	100%	100%	507
HID lighting improvements	2	450	-	1.13	$ 60	NA	$ 0.06	12%	100%	100%	104
Replace incandescent lamps with CFLs	13	140	-	1.45	$ NA	$ (0.14)	$ (0.01)	70%	100%	100%	50
Replace incandescent lamps with LEDs	9	160	-	0.21	$ 760	$ 0.05	$ 0.04	100%	100%	100%	157
Occupancy sensor for lighting	10	360	-	0.81	$ 50	NA	$ 0.02	38%	100%	50%	182
Daylight dimming system	20	140	-	1.51	$ 70	NA	$ 0.04	25%	85%	46%	172
Outdoor Lighting Controls	14	170		NA	$ 40	NA	$ 0.03	30%	100%	**100%**	**-**
											1,172
Office Equipment											
Office equipment	5	1,400	-	0.51	$ 0.01	$ 20	$ 0.003	50%	100%	100%	197
Turn off office equipment after-hours	5	6,800	NA	0.44	$ -	$ -	$ -	100%	100%	76%	256
											452
Appliances/Other											
Hot Food Holding Cabinets	15	1,800	6,165	NA	$ 450	NA	$ 0.02	25%	100%	100%	3
Commercial clothes washers—2.0 MEF	11	300	23,432	NA	$ 320	NA	$ 0.04	29%	100%	100%	2
											5
Existing Buildings Subtotal											**2,990**
New Buildings											
Efficient new building (15% savings)	17	NA	-	1.31	NA	$ 0.24	$ 0.02	18%	100%	100%	104
Efficient new building (30% savings)	17	NA	-	2.61	NA	$ 0.47	$ 0.02	35%	100%	100%	417
Tax credit eligible building (50% svgs)	17	NA	-	4.36	NA	$ 0.44	$ 0.01	18%	100%	100%	354
											875
										TOTAL	**3,865**

B.2.2. Natural Gas Analysis

To estimate the resource potential for efficiency in commercial buildings in Arkansas, we first develop a disaggregate characterization of baseline natural gas consumption in the state for current gas use and a reference load forecast (see Table B-8 below). Highly disaggregated commercial gas consumption data is unfortunately not available at the state level. To estimate these data, we start with current natural gas consumption for the Arkansas commercial sector (EIA 2008) and a forecast out to 2025 based on SERC forecasts, and we disaggregate by end-use using average regional data from CBECS 2003 (EIA 2006) and AEO 2007 (EIA 2007).

Table B-8. Baseline Commercial Natural Gas Consumption by End-Use (BBtu)

End-Use	2009	%	2015	%	2025	%
Heating	19,200	50%	19,800	50%	20,200	49%
Cooling	180	0.5%	180	0.5%	230	1%
HVAC subtotal	*19,400*	*51%*	*20,000*	*51%*	*20,400*	*50%*
Water Heating	7,600	20%	7,900	20%	8,700	21%
Cooking	4,000	10%	4,000	10%	4,400	11%
Other	7,100	19%	7,300	19%	7,700	19%
Total	**38,000**	**100%**	**39,300**	**100%**	**41,100**	**100%**

Next, we estimated commercial square footage in the state using natural gas intensity data (MBtu per square foot) by census region from CBECS (EIA 2006). We used the West South Central census division to estimate overall natural gas intensity for the state of Arkansas of 33 MBtu per square foot. Total natural gas consumption in the state divided by the natural gas intensity provides an estimate of commercial floorspace. Using this methodology, we estimate 765 million square feet of commercial floorspace in the state.

B.2.2.1 Measure Cost-Effectiveness

We then analyzed 20 efficiency measures for existing commercial buildings and 3 new construction whole-building measures to examine the cost-effective energy efficiency resource potential. For each efficiency measure, we estimated natural gas savings (Annual Savings per Measure) and incremental cost (Measure Cost) in a "replacement on burnout scenario," which assumes that the product is replaced or the measure is installed at the end of the measure's useful life. Savings and costs are incremental to an assumed Baseline Measure. We estimate savings (MMBtu) and costs ($) on a per-unit and/or a per-square foot commercial floorspace basis. For each measure we also assume a Measure Lifetime, or the estimated useful life of the product.

A measure is determined to be cost-effective if its levelized cost of saved energy, or cost of conserved energy (CCE), is less than $11.08/MMBtu, the estimated current average commercial cost of natural gas in Arkansas. The estimated CCE for each efficiency measure, which assumes a discount rate of 5%, are shown in the measure descriptions below. Equation 1 shows the calculation for cost of conserved energy.

Our assumed Baseline Measure, Annual Savings per Measure, Measure Cost, Measure Lifetime, and CCE are reported for each of the efficiency measures in the list of measure descriptions below. We group the 20 efficiency measures for existing commercial buildings by end-use and list the 3 new building measures last.

Equation 1. CCE = PMT ((Discount Rate), (Measure Lifetime), (Measure Cost)) / (Annual Savings per Measure (kWh))

B.2.2.2. Total Statewide Resource Potential

For each measure, we derived Annual Savings per Measure on a per square foot basis (MMBtu per square foot) for the applicable end-use. For measures that we only have savings on a per-unit or per-building basis, we first derive the percent savings and multiply by the Baseline Natural Gas Intensity for that end-use. The assumed baseline intensities for each end use are shown in Table B-9. As an example, for a specific HVAC measure we multiply its percent savings by the baseline gas intensity (MBtu per square foot) for the HVAC end-use.

Table B-9. Commercial End-Use Baseline Natural Gas Intensities (MMBtu per s.f.)

End Use	2009
Heating	16.8
Cooling	0.2
Ventilation	0.0
Water Heating	6.7
Cooking	3.4
Other	6.2
HVAC Subtotal	16.9
Total	**33.2**

To estimate the total efficiency resource potential in existing commercial buildings in Arkansas by 2025, we first adjusted the individual measure savings by an Adjustment Factor (See Equation 2). This factor accounts for two adjustments: the technical feasibility of efficiency measures, called the Percent Applicable (the percent of Arkansas floorspace that satisfy the base case conditions and other technical prerequisites such as heating fuel type and cooling equipment, etc); and the Current Market Share, or the percent of products that already meet the efficiency criteria. These assumptions are outlined in each of the efficiency measure descriptions below.

Equation 2. Adjustment Factor = Percent Applicable x (1-Current Market Share)

We then adjusted total savings for interactions among individual measures. For example, we must adjust HVAC equipment savings downward to account for savings already realized through improved building envelope measures (insulation and windows), which reduce heating and cooling loads. Similarly, we adjust water heating equipment savings to account for reduced water heating loads from the use of more efficient clothes washers. The multiplier for these adjustments is called the Interaction Factor.

Finally, we adjust replacement measures with lifetimes more than 7 and 17 years to only account for the percent turning over in 7 and 17 years, which represents the benchmark years of 2015 and 2025, respectively. Note that the multiplier, Percent Turnover, is only applicable to products being replaced upon burnout and not retrofit measures such as insulation. These retrofit measures therefore have 100% of measures "turning over."

We then calculate the resource potential for each measure in the state using Equation 3, which takes into account all of the adjustments described above. The sum of the resource potential from all measures is the overall energy efficiency resource potential in the state's commercial buildings sector.

B.2.3. Efficiency Measures

Table B-10 shows the thirty-eight efficiency measures examined for this analysis, grouped by end-use costs, savings (MBtu) per product or square foot, *Percent Applicable, Interaction Factor, Percent Turnover,* and total savings potential (MMBtu) in 2025. Detailed descriptions of each measure are given below, grouped by end-use.

Building Shell Improvements

Roof Insulation

Measure Description: Fiberglass or cellulose insulation material in roof cavities will reduce heat transfer, though the type of building construction limits insulation possibilities. R-values describe the performance factor for insulation levels.

Basecase: The basecase electricity intensity for this measure was disaggregated from the post-savings electricity intensity and the percentage of savings.

Data Explanation: We assume 3% savings and a post-savings gas intensity 16.4 Mbtu/ft^2/year, based on an average of four building types (ACEEE 1997). An average lifetime of 25 years (CL&P 2007) and an incremental cost of 12 cents/ft^2 were also assumed. The measure is shared with gas savings as well, so the portion of the incremental cost attributed to gas savings is 4 cents/sf. The levelized cost is $5.69/MMBtu.

Double Pane Low-Emissivity Windows

Measure Description: Double-pane windows have insulating air- or gas-filled spaces between each pane, which resist heat flow. Low-emissivity (low-e) glass has a special surface coating to reduce heat transfer back through the window, and a window's R-value represents the amount of heat transfer back through a window. Low-e windows are particularly useful in climates with heavy cooling loads, because they can reflect anywhere from 40% to 70% of the heat that is normally transmitted through clear glass. The Solar Heat Gain Coefficient (SHGC) represents the fraction of solar energy transferred through a window. For example, a low-e window with a 0.4 SHGC keeps out 60% of the sun's heat.

Basecase: The basecase electricity intensity for this measure was disaggregated from the post-savings electricity intensity and the percent savings.

Data Explanation: Percent savings of 3% apply to whole-building electricity consumption (ACEEE 1997). Incremental costs assume $2 per window (SWEEP 2002). As with roof insulation, this measure is shared with gas savings. A measure life of 25 years is from SWEEP 2002. Percent applicable is an ACEEE estimate. The levelized cost is calculated to be $3.77/MMBtu.

Heating and Cooling: Equipment and Controls

Boiler Tune-Up

Measure Description: A boiler tune-up should be done regularly to keep the boiler system running at optimal efficiency.

Basecase: Same basecase as for high-efficiency main/front-end boilers is assumed (#4).

Data Explanation: A boiler tune-up saves 2% of the energy of a baseline unit annually, or 30 MMBtu, and has an incremental cost of $250 per boiler (GDS 2005). Percent applicable of 13% was calculated using CBECS data of percentage of buildings with boilers that don't perform regular maintenance (CBECS 2003). We assume a measure life of 2 years (GDS 2005). The levelized cost is $6.08/MMBtu.

Duct Sealing

Measure Description: Duct sealing involves sealing gaps in ductwork that allow conditioned air to escape.

Basecase: The basecase is standard heating and cooling energy intensity, 16.9 MBtu/ft^2. This is the average of data for the West South Central census division (from the EIA's commercial building survey) and the AEO.

Data Explanation: This measure saves 18% (48 MMBtu) of heating and cooling energy annually, and has an incremental cost of $7,000 (Sachs et al. 2004). Percent applicable is 37% based on the number of buildings under 25,000 sf, and the measure life is 25 years (Sachs et al. 2004). The levelized cost is $10.35/MMBtu.

Pipe Insulation

Measure Description: This measure includes insulating accessible steam or hot water supply pipes in the boiler room.

Basecase: The basecase is standard heating energy intensity, 16.8 MBtu/ft^2. This is the average of data for the West South Central census division (from the EIA's commercial building survey) and the AEO.

Data Explanation: This measure saves 2% (5 MMBtu) of heating energy annually (NYSERDA 2006), and has an incremental cost of $450, based on an ACEEE estimate of 75 feet of pipe to insulate at $6 per linear foot of pipe (RSMeans). Percent applicable is 48%, current market share is 75%, and the measure life is 15 years (NYSERDA 2006). The levelized cost is $8.41/MMBtu.

High-Efficiency Rooftop Furnace Unit

Measure Description: This measure involves technologies such as condensing units to capture latent heat from water vapor in the flue, and modulating units which have a variable firing rate to match the output to heat load.

Basecase: The basecase is a 10 ton gas-fired condensing rooftop packaged unit with 80% steady state efficiency. The average annual gas use is 179 MMBtu (Sachs et al. 2004).

Data Explanation: A high efficiency rooftop unit uses 150 MMBtu/year, saves 16% of basecase energy, and has an incremental cost of $1,000 (Sachs et al. 2004). Percent applicable is 35% based on the percent of buildings less than 100,000 square feet multiplied by the assumption that the following percentages of size buildings use rooftop units: 40% of buildings 1,000-5,000 sf, 80% of buildings 5,000-25,000 sf, and 66% of buildings 25,000-100,000 sf. This assumption is based on CBECS data as well as ACEEE estimates. We assume a measure life of 15 years and 0% current market share (Sachs et al. 2004). The levelized cost is shown to be $3.42/MMBtu.

High-Efficiency Standalone Furnace

Measure Description: This measure replaces minimum-efficiency gas furnaces with condensing furnaces and/or modulating capacity (variable firing rate that matches the output to heat load).

Basecase: The basecase is a 80 AFUE residential furnace. The average annual gas use is 142 MMBtu (ENERGY STAR figure modified by a factor of 1.45 to represent the slightly larger average size of a small commercial building than a residential building).

Data Explanation: A high efficiency furnace with 90 AFUE (ENERGY STAR minimum) uses 126 MMBtu/year, saves 11% of basecase energy, and has an incremental cost of $464 (ENERGY STAR; cost and savings modified as per basecase). Percent applicable is 2% based on the percent of buildings less than 5,000 square feet multiplied by the assumption that 40% of smaller buildings use furnaces. This assumption is based on CBECS data as well as ACEEE estimates. We assume a measure life of 18 years and 35% current market share (ENERGY STAR). The levelized cost is shown to be $2.51/MMBtu.

High-Efficiency Boiler

Measure Description: Substitution of condensing boilers with outdoor reset or equivalent controls (including circulation pump time clocks) for basecase non-condensing boilers without adaptive controls (just thermostats and equivalent).

Basecase: A case study of boilers with 68% efficiency was assumed. The average annual gas use is 1,106 MMBtu, which was modified from the original statistic (26,267 MMBtu) to account for the difference in the case study building size and the average commercial building size in Arkansas (Sachs et al. 2004).

Data Explanation: Boilers with 90% efficiency use 832 MMBtu/year in an average commercial building, save 50% of basecase energy (Durkin), and have an incremental cost of $3,024 (Sachs et al. 2004). The cost reflects the incremental cost of a high-efficiency boiler as well as the cost of an outdoor temperature reset system. Percent applicable is 57% based on assumptions of percentage of buildings in each size class that use boilers and an assumption of 90% that can be easily replaced, per CBECS and ACEEE estimates. We assume a measure life of 24 years (Sachs et al. 2004). The levelized cost is shown to be $0.80/MMBtu.

Programmable Thermostat

Measure Description: This measure involves replacing conventional thermostats with programmable thermostats. This measure is only appropriate to smaller buildings.

Basecase: The basecase of 34 MBtu/ft2 is the standard heating and cooling intensity modified by the overall intensity ratio of small buildings to the average (EIA 2006 and 2007).

Data Explanation: This measure saves 5% (3 MMBtu) of heating energy annually (RLW 2007). The measure has an incremental cost of $101 (CEC 2005) and a percent applicable of 14%. The percent applicable derives from the percentage of West South Central commercial buildings under 2,000 s.f. and the fact that 80% of these buildings do not have an EMS (EIA 2006). The measure life is 12 years (GDS 2005) and the levelized cost is $4.55/MMBtu.

Demand-Controlled Ventilation

Measure Description: Often, HVAC systems are designed to supply ventilated air based on assumed occupancy levels, resulting in over-ventilation. Demand-controlled ventilation monitors CO_2 levels in different zones and delivers the required ventilation only when and where it is needed.

Basecase: The basecase energy use is 215 MMBtu/year, or the portion of commercial gas heating attributable to ventilation (Sachs et al. 2004).

Data Explanation: Demand-controlled ventilation saves 20% of the ventilation energy a year (43 MMBtu), and has an incremental cost of $575 per zone (six zones were assumed as an average, for a total cost of $3,450) (Sachs et al. 2004). Percent applicable is 54%, and the measure life is 15 years (Sachs et al. 2004). The levelized cost is $7.75/MMBtu.

Outdoor Temperature Boiler Reset

Measure Description: Normally, boilers heat water to a fixed temperature. With an outdoor air reset system, the maximum temperature the boiler operates at is variable, depending on the outdoor temperature. The warmer the outdoor temperature, the lower the boiler temperature needs to be, saving energy over the standard fixed (high) temperature operation of a conventional boiler.

Basecase: The basecase is standard heating energy intensity, 16.8 MBtu/ft2. This is the average of data for the West South Central census division (from the EIA's commercial building survey) and the AEO.

Data Explanation: This measure saves 2% (5 MMBtu) of heating energy annually (NYSERDA 2006), and has an incremental cost of $600 (GDS 2005). Percent applicable is 5%, based on the percent of boilers not included in the High Efficiency Boiler measure. The current market share is 60% (NYSERDA 2006), and the measure life is 15 years (ACEEE 2006). The levelized cost is $11.03/MMBtu.

Water Heating

Tank Insulation

Measure Description: Commercial water heater insulation is available either by the blanket or by square foot of fiberglass insulation with protective facing.

Basecase: The basecase is standard water heating energy intensity, 9.1 MBtu/ft^2. This is the average of data for the Mid-Atlantic region (from the EIA's commercial building survey) and the AEO.

Data Explanation: This measure saves 2% (4 MMBtu) of water heating energy annually (NYSERDA 2006), and has an incremental cost of $11.95 per square foot (RSMeans) with an assumed 180 square feet of tank surface area. Percent applicable is 50%, current market share is 53%, and the measure life is 15 years (NYSERDA 2006). The levelized cost is $11.91/MMBtu.

Smart Circulation Pump Controls

Measure Description: This measure involves shutting down the DHW recirculation pump during periods when there is little or no demand for hot water. These periods are determined by the controls from historical use patterns. This leads to savings from heat loss through piping, as well as savings associated with the running of the pump.

Basecase: The basecase is standard water heating energy intensity, 6.7 MBtu/ft^2. This is the average of data for the West South Central census division (from the EIA's commercial building survey) and the AEO.

Data Explanation: This measure saves 3% (3 MMBtu) of water heating energy annually, and has an incremental cost of $143 (GDS 2005). Percent applicable is 5% based on the percent of buildings with boilers that are not covered in the high efficiency boiler measure, and the measure life is 15 years (GDS 2005). The levelized cost is $4.48/MMBtu.

Condensing DHW Stand-Alone Tank

Measure Description: This measure involves a new high-efficiency residential-sized tank-type gas water heater, for smaller commercial operations.

Basecase: The basecase is standard water heating energy intensity, 6.7 MBtu/ft^2. This is the average of data for the West South Central census division (from the EIA's commercial building survey) and the AEO.

Data Explanation: This measure saves 36% (37 MMBtu) of water heating energy annually (NYSERDA 2006), and has an incremental cost of $1,100 (Sachs et al. 2004). Percent applicable is 35%, current market share is 5%, and the measure life is 15 years (NYSERDA 2006). The levelized cost is $2.87/MMBtu.

Indirect-Fired DHW Off Space Heating Boiler

Measure Description: DHW cylinders are heated indirectly with water from the boiler.

Basecase: The basecase is standard water heating energy intensity, 6.7 MBtu/ft^2. This is the average of data for the West South Central census division (from the EIA's commercial building survey) and the AEO.

Data Explanation: This measure saves 30% (30 MMBtu) of water heating energy annually (NYSERDA 2006), and has an incremental cost of $4,000. Percent applicable is 5%, the current market share is close to 0%, and the measure life is 25 years (NYSERDA 2006). The levelized cost is $9.38/MMBtu.

Instantaneous High-Modulating Water Heater

Measure Description: "Instant" or "tankless" water heaters heat water on demand. Advanced units have modulating burners with electronic controls to maintain constant outlet temperature despite variations in inlet temperature and variable demand.

Basecase: The basecase is standard water heating energy intensity, 6.7 MBtu/ft^2. This is the average of data for the West South Central census division (from the EIA's commercial building survey) and the AEO.

Data Explanation: This measure saves 21% (21 MMBtu) of water heating energy annually (NYSERDA 2006), and has an incremental cost of $650 (Sachs et al. 2004). Percent applicable is 4%, the current market share is 26%, and the measure life is 15 years (NYSERDA 2006). The levelized cost is $2.98/MMBtu.

Cooking

Direct Fired Convection Range/Oven

Measure Description: Convection ovens use a small fan to circulate hot air within the oven cavity. Circulating air can heat food more efficiently than the still air found in conventional ovens.

Basecase: A conventional range/oven uses approximately 160 MMBtu/year (Food Service Technology Center 2002).

Data Explanation: This measure saves 35% (56 MMBtu) per year per unit (GDS 2005), and has an incremental cost of $2,625 (RSMeans 2008). The measure life is 8 years and the percent applicable is 5%, which accounts for weighted applicability in only the commercial sectors that would have ovens (NYSERDA 2006). The levelized cost is $7.25/MMBtu.

High Efficiency ENERGY STAR Fryer

Measure Description: ENERGY STAR fryers can save 15-25% of the energy used by a conventional model. High-efficiency gas fryers utilize technology such as heat pipes, infrared burners, recirculation tubes, power burners, and pulse combustion.

Basecase: A conventional fryer uses 163 MMBtu per year on average (EPA 1007).

Data Explanation: An ENERGY STAR fryer saves 31% (51 MMBtu) per year per unit, and has an incremental cost of $3,795 (ENERGY STAR). Current market share is 11% (EPA 2007), and the Arkansas stock data (80,000 units) was derived from national annual shipments (EPA 2007), measure life (12 years—ENERGY STAR), and the ratio of commercial buildings that include cooking equipment that use natural gas (CBECS). The levelized cost is $8.48/MMBtu.

High Efficiency ENERGY STAR Steam Cooker

Measure Description: ENERGY STAR steam cookers have better insulation to reduce heat loss, and a more efficient steam delivery system. These steamers can be up to 50% more energy-efficient than conventional steamers.

Basecase: A conventional steamer uses 91 MMBtu per year on average (data derived from ENERGY STAR and Food Service Technology Center data).

Data Explanation: An ENERGY STAR steam cooker saves 50% (45 MMBtu) per year per unit (ENERGY STAR), and incremental cost is a net savings of $1,995 (CEC 2005). Current market share is 8%, and the Arkansas stock data (33,000 units) was derived from national annual shipments (ENERGY STAR) , measure life (10 years—Food Service Technology Center 2002), and the ratio of commercial buildings that include cooking equipment that use natural gas (EIA 2006). The levelized cost is a net savings of $5.63/MMBtu.

High Efficiency Griddle

Measure Description: High efficiency griddles take advantage of technologies such as double sided griddles, chrome finishes, snap-action thermostats, infrared burners, heat pipes, thermal fluid or steam to reduce energy consumption.

Basecase: A conventional griddle uses 112 MMBtu per year on average (Food Service Technology Center 2002).

Data Explanation: A high efficiency griddle saves 14% (15 MMBtu) of energy per year per unit (GDS 2005), and has an incremental cost of $50 (CEC 2005). Percent applicable is 90%. The levelized cost is $0.37/MMBtu.

Miscellaneous

Retrocommissioning

Measure Description: Retrocommissioning results in optimized energy usage of buildings through better operations and maintenance, control calibration, and facilities staff training.

Basecase: The basecase is average heating, cooling, and water heating energy intensity, 23.6 MBtu/ft^2. This is the average of data for the West South Central census division (from the EIA's commercial building survey) and the AEO.

Data Explanation: This measure saves 10% (36 MMBtu) of heating, cooling, and water heating energy (Sachs et al. 2004), and has an incremental cost of $0.25 per square foot. This cost is shared with electric savings from the same measure, so the actual cost of gas savings is $0.11. Percent applicable is 54%, and the measure life is 7 years (Sachs et al. 2004). The levelized cost is $7.89/MMBtu.

New Buildings

Efficient New Building (15% Savings)

Measure Description: Incorporating energy efficiency into building design is best achieved at the time of construction. New buildings can achieve major energy savings in heating and cooling, as well as energy-saving appliances.

Basecase: The basecase is 14.5 MBtu/ft2 per year, based on the HVAC and water heating energy intensities for commercial buildings built between 2000 and 2003 (EIA 2006).

Data Explanation: Incremental cost of $0.35 per ft2 and measure life of 17 years are from NGRID 2007. The cost is shared with electric savings from the same measure, so the actual cost for gas savings is $0.11. Percent applicable of 18% for this new buildings measure assume that 30% and 50% new buildings savings are phased in one to two years prior to enactment of codes in the policy scenarios (30% in 2012 and 50% in 2020). The levelized cost is calculated to be $4.68/MMBtu.

Efficient New Building (30% Savings)

Measure Description: Incorporating energy efficiency into building design is best achieved at the time of construction. New buildings can achieve major energy savings in heating and cooling, as well as energy-saving appliances.

Basecase: The basecase is 14.5 MBtu/ft2 per year, based on the HVAC and water heating energy intensities for commercial buildings built between 2000 and 2003 (EIA 2006).

Data Explanation: In New York, estimates show that commercial buildings can reach 30% beyond code at an investment of $0.70/kWh. To be conservative, we estimate $0.70/kWh by doubling the costs of a 15%-beyond-code building. The cost is shared with electric savings from the same measure, so the actual cost for gas savings is $0.23. Measure life of 17 years is from NGRID 2007. Percent applicable of 35% for 30% savings new buildings assume that 30% and 50% new buildings savings are phased in one to two years prior to enactment of codes in the policy scenarios (30% in 2012 and 50% in 2020). The levelized cost is calculated to be $4.68/MMBtu.

Tax-Credit Eligible Building (50% Savings)

Measure Description: A federal tax incentive is available for new buildings that are constructed to save at least 50% of the heating, cooling, ventilation, water heating, and interior lighting cost of a building that meets ASHRAE standard 90.1-2001.

Basecase: Basecase of 14.5 MBtu per ft2 is an estimate of HVAC, water heating, and lighting end-use electricity intensity for new buildings in Arkansas, derived from data for buildings built from 2000–2003 (EIA 2006).

Data Explanation: Incremental costs of $0.66 per ft2 are derived from NREL (2008) studies on energy savings for medium box retail stores and supermarkets. This cost is shared with electric savings from the same measure, so the actual cost for gas savings is $0.22. Percent applicable is 18%, accounting only for the share of buildings that call into the two types of buildings covered in the NREL studies. Measure life of 17 years is from NGRID 2007. The levelized cost is calculated to be $2.65/MMBtu.

Table B-10. Commercial Natural Gas Measure Characterizations

Measures	Measure Life (Years)	Annual MMBtu svgs per unit	2007 Arkansas Stock	MBtu svgs per s.f.	Incremental cost per unit	Incremental cost per s.f.	Cost of Conserved Energy (2006$/MMBtu saved)	Adjustment Factor	% Turnover	Interaction Factor	Savings in 2025 (BBtu)
Existing Buildings											
Building Shell											
Roof insulation	25	8	NA	0.53	-	$ 0.04	$ 5.69	35%	100%	100%	96
Low-e windows	25	8	NA	0.51	-	$ 0.03	$ 3.77	75%	100%	100%	197
HVAC											
Boiler tune-up	2	22	NA	1.44	$ 250	$ -	$ 6.08	13%	100%	100%	143
Duct sealing	25	48	NA	3.12	$ 7,000	$ 0.46	$ 10.35	37%	68%	100%	594
Pipe insulation—heating	15	5	NA	0.34	$ 450	$ -	$ 8.41	12%	100%	100%	31
Load-Reducing Measures Subtotal											**768**
High Efficiency rooftop furnace unit	15	28	NA	1.83	$ 1,000	$ -	$ 3.42	35%	100%	94%	462
High efficiency standalone furnace	18	16	NA	1.03	$ 464	$ -	$ 2.51	1%	94%	94%	9
High efficiency main/front-end boiler	24	274	NA	17.83	$ 3,024	$ -	$ 0.80	51%	71%	94%	4,663
HVAC Equipment Measures Subtotal											**5,134**
Programmable thermostat	12	3	NA	1.69	$ 100	$ -	$ 4.55	14%	100%	55%	96
Demand-controlled ventilation	15	43	NA	2.79	$ 3,450	$ -	$ 7.75	54%	100%	55%	629
Outdoor temperature boiler reset	15	5	NA	0.34	$ 600	$ -	$ 11.03	2%	100%	55%	3
HVAC Control Measures Subtotal											**727**
HVAC Subtotal											**6,629**
Water Heating											
Circulation pump time clock	15	3		0.20	$ 140	$ -	$ 4.48	5%	100%	100%	7
Control Measures Subtotal											**7**
Condensing DHW stand-alone tank	15	37	NA	2.40	$ 1,100	$ -	$ 2.87	33%	100%	100%	606
Indirect-fired DHW off space heating boiler	25	30		1.97	$ 4,000	$ -	$ 9.38	5%	68%	100%	55
Tankless high-modulating water heater	15	21		1.37	$ 650	$ -	$ 2.98	3%	100%	100%	32
Equipment Measures Subtotal											**692**
Water Heating Subtotal											**699**
Cooking											
Direct fired convection range/oven	8	56	104,000	NA	$ 2,630	$ -	$ 7.25	5%	100%	100%	318
High efficiency ENERGY STAR fryer	12	51	80,000	NA	$ 3,800	$ -	$ 8.48	11%	100%	100%	443

High efficiency ENERGY STAR steam cooker	10	45	33,000	NA	$ (1,960)	$ -	$ (5.63)	8%	100%	100%	118
High efficiency griddle	12	15	19,000	NA	$ 50	$ -	$ 0.37	90%	100%	100%	15
											893
Miscellaneous											
Retrocommissioning	7	36	NA	2.36	$ -	$ 0.11	$ 7.89	54%	100%	100%	975
											975
Existing Buildings Subtotal											**9,490**
New Buildings											
Efficient new building (15% savings)	17	NA	NA	2.17	NA	$ 0.11	$ 4.68	18%	100%	100%	395
Efficient new building (30% savings)	17	NA	NA	4.35	NA	$ 0.23	$ 4.68	35%	100%	100%	1,582
Tax credit eligible building (50% svgs)	17	NA	NA	7.25	NA	$ 0.22	$ 2.65	18%	100%	100%	1,345
											3,321
										TOTAL	**12,811**

B.3. Industrial Sector

B.3.1. Overview of Approach

According to *2006 Manufacturing Energy Consumption Survey (MECS)* (EIA 2009), the South region (which includes Arkansas) industrial energy use is broken down as follows: electricity (15%), natural gas (34%), fuel oil (3%), coal & coke (5%), and other (43%). Therefore, this analysis focused on the electricity and natural gas savings potential. It was accomplished in several steps. First, the industrial market in Arkansas was characterized at a disaggregated level and energy consumption for key end-uses was estimated. Then cost effective energy-saving measures were selected based on the projected average retail industrial electricity and natural gas prices. The economic potential savings for these measures was estimated by applying the efficiency measures to end-use energy consumption. The following sections described the process for estimating the savings potential in Arkansas.

B.3.2. Market Characterization and Estimation of Base Year Electricity Consumption

The industrial sector is made up of a diverse group of economic entities spanning agriculture, mining, construction and manufacturing. Significant diversity exists within most of these industry sub-sectors, with the greatest diversity within manufacturing. The various product categories within manufacturing are classified using the North American Industrial Classification System (NAICS) (Census 2002).[56]

Comprehensive, highly-disaggregated electricity or natural gas data for the industrial sector is not available at the state level. To estimate the electricity and natural gas consumption, this study drew upon a number of resources, all using the NAICS system and a consistent sample methodology. Fortunately, a conjunction of the various economic censuses for each state allows us to use a common base-year of 2002.

We then used national industry energy intensities derived from industry group electricity and natural gas consumption data reported in the *2005 Annual Energy Outlook* (AEO) (EIA 2005) and value of shipments data reported in the *2002 Annual Survey of Manufacturing* (ASM) (Census 2005) to apportion industrial energy consumption. These intensities were then applied to the value of shipments data for the manufacturing energy groups (three-digit NAICS) in Arkansas. These energy consumption estimates were then used to estimate the share of the industrial sector electricity and natural gas consumption for each sub-sector.

Preparation of Baseline Industrial Electricity Forecast

As is the case for state-level energy consumption data, no state-by-state disaggregated electricity or natural gas consumption forecasts are publicly available. Several alternate data sources were used to calculate estimated energy consumption growth rates for each state and sub-sector. We made the assumption that energy consumption will be a function of gross state value of shipments (VOS). Electricity and natural gas consumption, however, will not grow at the same rate as value of shipments. This is because in general, energy intensity (energy consumed per value of output) decreases with time.

Because state-level disaggregated economic growth projections are not publicly available, data was used from Moody's Economy.com. The average growth rate for specific industrial-subsectors was estimated based on Economy.com's estimates of gross state product. We used this estimated industrial energy consumption distribution to apportion the EIA estimate (2005) of industrial energy consumption.

[56] The industry sector is comprised of four sub-sectors: Manufacturing, Mining, Agriculture, and Construction. Each sub-sector is further broken down into individual industry groups reflecting the many different definitions for the term 'industrial.'

The industry sector is comprised of four sub-sectors: Manufacturing, Mining, Agriculture, and Construction. The manufacturing sector is broken down into 21 subsectors, defined by three digit NAICS codes. In order to most closely match available data from the *ASM* and *AEO*, three subsectors were further broken down to four digit NAICS codes: chemical manufacturing, nonmetallic mineral product manufacturing, and primary metal manufacturing. Table B-11 below shows the estimated electrical and natural gas consumption for all these subsectors in Arkansas in 2008.

Table B-11. 2008 Base-Case Electricity Consumption by Industry in Arkansas

Industry	NAICS Code	Electricity		Natural Gas	
		(GWh)	(%)	(BBtu)	(%)
Agriculture	**11**	**1,494**	**9%**	**5,100**	**6%**
Mining	**21**	**388**	**2%**	**3,530**	**4%**
Construction	**23**	**256**	**2%**	**1,668**	**2%**
Food mfg	311	2,054	12%	13,802	16%
Beverage & tobacco product mfg	312	101	1%	333	0%
Textile mills	313	8	0%	28	0%
Textile product mills	314	47	0%	154	0%
Apparel mfg	315	79	0%	262	0%
Leather & allied product mfg	316	37	0%	122	0%
Wood product mfg	321	626	4%	2,177	2%
Paper mfg	322	1,679	10%	9,671	11%
Printing & related support activities	323	125	1%	413	0%
Petroleum & coal products mfg	324	376	2%	6,133	7%
Chemical mfg	325	1,845	11%	16,464	19%
Pharmaceutical & medicine mfg	*3254*	*0*	*0%*	*0*	*0%*
All other chemical products	*-3253,3255-*	*1,845*	*11%*	*16,464*	*19%*
Plastics & rubber products mfg	326	776	5%	2,836	3%
Nonmetallic mineral product mfg	327	876	5%	1,867	2%
Glass & glass product mfg	*3272*	*44*	*0%*	*405*	*0%*
Cement & concrete product mfg	*3273*	*741*	*4%*	*1,160*	*1%*
Other minerals	*3271,3274-*	*91*	*1%*	*302*	*0%*
Primary metal mfg	331	4,071	24%	17,281	20%
Iron & steel mills & ferroalloy mfg	*3311*	*1,422*	*8%*	*9,135*	*10%*
Steel product mfg from purchased steel	*3312*	*465*	*3%*	*2,988*	*3%*
Alumina and Aluminum	*3313*	*1,251*	*7%*	*2,408*	*3%*
Nonferrous Metals, except Aluminum	*3314*	*720*	*4%*	*1,386*	*2%*
Foundries	*3315*	*212*	*1%*	*1,364*	*2%*
Fabricated metal product mfg	332	414	2%	1,021	1%
Machinery mfg	333	314	2%	771	1%
Computer & electronic product mfg	334	190	1%	479	1%
Electrical equipment, appliance, & component mfg	335	448	3%	1,120	1%
Transportation equipment mfg	336	536	3%	1,339	2%
Furniture & related product mfg	337	194	1%	642	1%
Miscellaneous mfg	339	141	1%	467	1%
Total Industrial Sector		**17,076**	**100%**	**87,679**	**100%**

B.3.3. Market Characterization Results

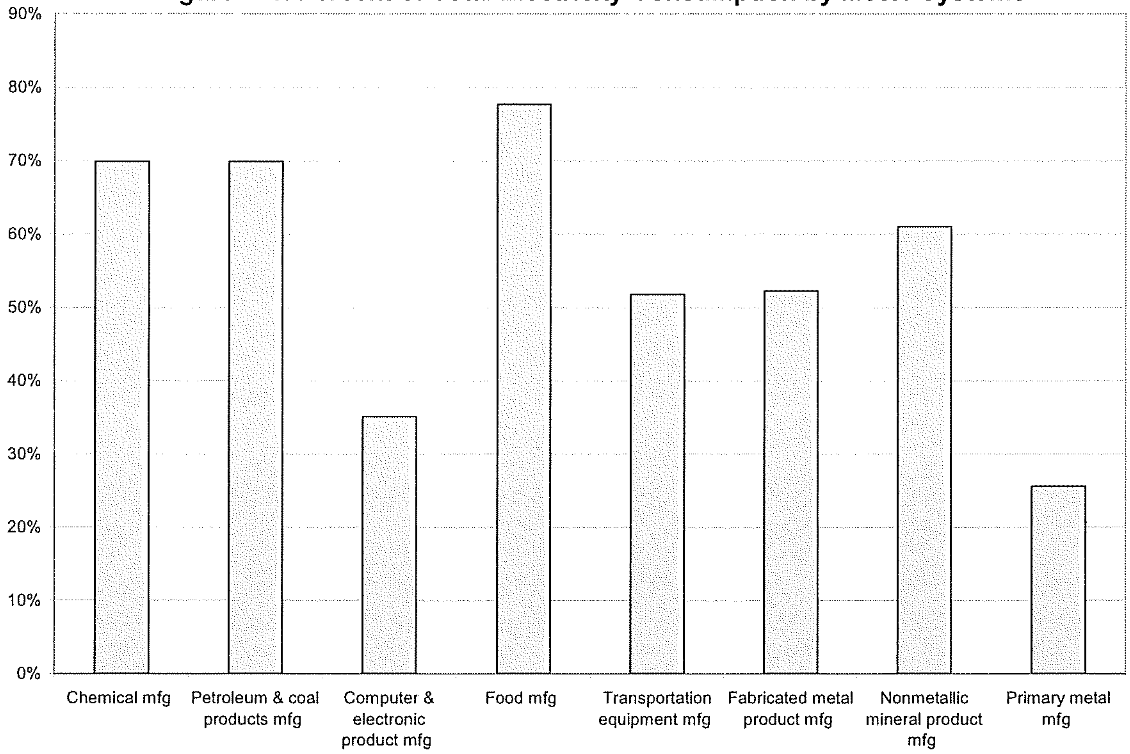
In 2008, the State of Arkansas industrial sector consumed 17,076 GWh of electricity and 87,679 billion Btus of natural gas. Within the manufacturing sector, the primary metal, food, chemical, and paper manufacturing industries are the largest consumers of energy, accounting for 57% of electricity consumption and 65% of natural gas.

Industrial Electricity End Uses

In order to determine the electricity savings for any technology, the fraction of the electricity to which the technology is applicable must be determined. Much of the energy consumed by industry is directly involved in processes required to produce various products. Electricity accounts for about a third of the primary energy used by industries (EIA 2005). Electricity is used for many purposes, the most important being to run motors, provide lighting, provide heating, and to drive electrochemical processes.

While detailed end-use data is only available for each manufacturing sub-sector and group through the MECS survey (EIA 2005), motor systems are estimated to consume 60% of the industrial electricity (Xenergy 1998). The fraction of total electricity attributed to motors is presented in Figure B-1.

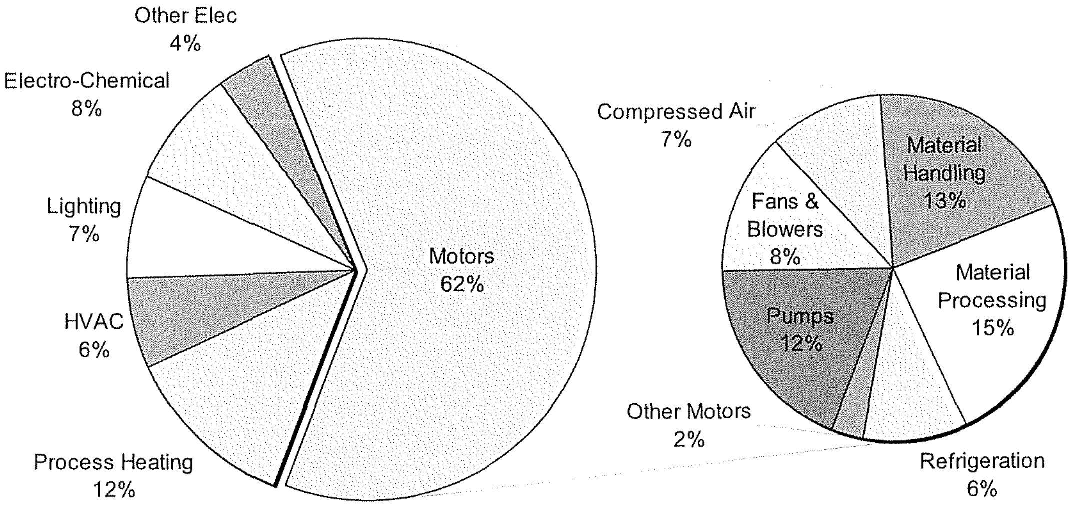
Figure B-1. Percent of Total Electricity Consumption by Motor Systems



Source: XENERGY (1998)

Motors are used for many diverse applications from fluid applications (pumps, fans, and air and refrigeration compressors), to materials handling and processing (conveyors, machine tools and other processing equipment). The distribution of these motor uses varies significantly by industry, with material processing being the largest consumer in the sector. Figure B-2 shows the total weighted average of end-use electricity consumption in Arkansas with a breakdown of motors use in the state.

Figure B-2. Weighted Average of Total Industrial Electricity End-Uses in Arkansas with Breakdown of Industrial Motor System End-Uses

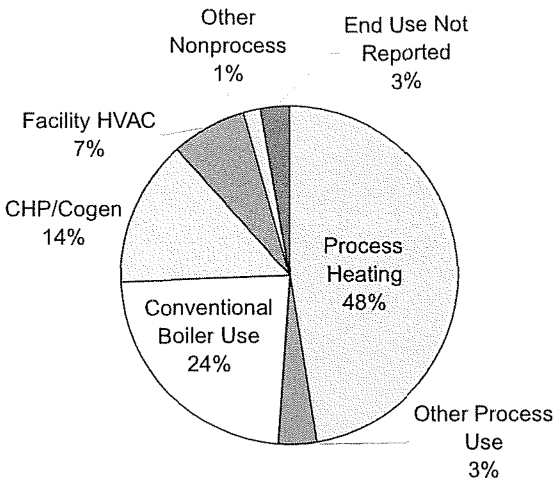


As discussed above, motors make up the majority of industrial electricity use. Electricity use for process heating is also significant, mostly due to the large amount of primary metals manufacturing, particular iron & steel.

Industrial Natural Gas End Uses

A similar methodology was used to determine industrial natural gas end use. The MECS survey (EIA 2005) provided both end use categories and nationwide consumption by industry, which was then applied to the actual industry mix in Arkansas.

Figure B-3. Weighted Average of Total Industrial Natural Gas End-Uses in Arkansas



Direct process heating is responsible for nearly half of natural gas use in Arkansas, followed by boilers, which account for close to 40%.

B.3.4. Overview of Efficiency Measures Analyzed

The first step in our technology assessment was to collect limited information on a broad "universe" of potential technologies. Our key sources of information included the DOE, Office of Industrial

Technologies; the Center for the Analysis and Dissemination of Demonstrated Energy Technologies (CADDET); Lawrence Berkeley National Laboratory (LBNL) and American Council for an Energy-Efficient Economy reports; information from NYSERDA; and Itron. We did not collect any primary data on technology performance.

Oftentimes, no one source provided all of the information we sought for our assessment (energy use, energy savings compared to average current technology, investment cost, operating cost savings, lifetime, etc.). We therefore made our best effort to combine readily available information along with expert judgment where necessary.

We sought to identify technologies that could have a large potential impact in terms of saving energy. These may be technologies that are specific to one process or one industry sector, or so-called "cross-cutting" technologies that are applicable to a variety of sectors. In estimating energy savings, we first identified the specific energy savings of each technology by comparing the energy used by the efficient technology to the energy required by current processes. Our second step was to "scale up" this savings estimate to see how much energy savings—for industry overall—this technology would achieve. For the most part, we derived specific energy savings information from the various technology assessment studies noted above.

In scaling up the technology-specific energy savings, we relied on our general knowledge of the various industrial processes to which this technology could be applied. We also took into account structural limitations to the penetration of the technology. Additionally, we recognized that market penetration, in the absence of significant policy support, can take time given the slowness of stock turnover in many industrial facilities.

Electricity Measures

We identified 14 measures that were cost effective at the average projected industrial electricity rates in Arkansas of $0.063/kWh (see Table B-12). The cost and performance of these measures has been developed over the past decade by ACEEE from research into the individual measures and review of past project performance. The costs of many of these measures has increased in recent years as a result of significant increases in key commodity costs such as copper, steel and aluminum, as well as overall manufacturing costs due to energy prices and market pressures. The estimates presented in Table B-12 represent ACEEE most current estimates. We present the full normalized installed measure cost (i.e., the full cost required to install a measure per unit of saved energy) as well as the levelized cost (i.e., the annual cost of the measure amortized over the life of the measure).

Table B-12. Cost and Performance of Industrial Electricity Measures

Measure	Measure Life	Cost of Saved Energy		Annual Savings for End-Use
		Installed cost/kWh	Levelized cost/kWh	
Sensors & Controls	15	$0.145	$0.014	3%
EIS	15	$0.635	$0.061	1%
Duct/Pipe insulation	20	$0.653	$0.052	20%
Electric supply	15	$0.104	$0.010	3%
Lighting	15	$0.212	$0.020	23%
Advanced efficient motors	25	$0.491	$0.035	6%
Motor management	5	$0.079	$0.018	1%
Lubricants	1	$0.000	$0.000	3%
Motor system optimization	15	$0.097	$0.009	1%
Compressed air manage	1	$0.000	$0.000	17%
Compressed air –advanced	15	$0.001	$0.000	4%
Pumps	15	$0.083	$0.008	20%
Fans	15	$0.249	$0.024	6%
Refrigeration	15	$0.034	$0.003	10%

In addition, we estimated the average normalized cost of industrial energy efficiency investments to be $0.28/kWh saved. This estimate was arrived at by estimating the sum of the annual incremental savings for each measure in each industry based on end-use energy distribution and dividing the corresponding total investment required.

Natural Gas Measures

We identified 33 measures that were cost effective at the average projected industrial natural gas rate in Arkansas of $8.21/mmBtu (see Table B-13). The cost and performance of these measures were taken from a 2006 Itron report. We present the full normalized installed measure cost (i.e., the full cost required to install a measure per unit of saved energy) as well as the levelized cost (i.e., the annual cost of the measure amortized over the life of the measure).

Table B-13. Cost and Performance of Industrial Natural Gas Measures

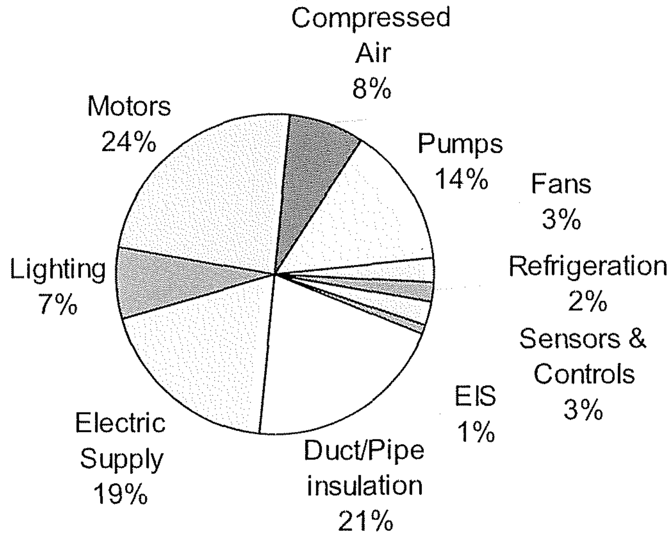
Measure	Measure Life	Installed Cost ($/mmBtu Saved)	Levelized Cost ($/mmBtu Saved)	Annual Savings for End-Use
Boiler Measures				
Improved process control	15	$1.23	$0.12	3%
Maintain boilers	2	$0.02	$0.01	10%
Flue gas heat recovery/economizer	15	$3.48	$0.34	2%
Blowdown steam heat recovery	15	$3.06	$0.29	1%
Upgrade burner efficiency	20	$2.50	$0.20	1%
Water treatment	10	$0.63	$0.08	1%
Load control	15	$1.36	$0.13	4%
Improved insulation	15	$6.55	$0.63	8%
Steam trap maintenance	2	$0.84	$0.45	13%
Automatic steam trap monitoring	15	$3.41	$0.33	5%
Leak repair	2	$0.22	$0.12	4%
Condensate return	15	$9.57	$0.92	10%
HVAC Measures				
Improve ceiling insulation	20	$85.70	$6.88	24%
Install HE(95%) cond. furnace/boiler	20	$37.88	$3.04	18%
Stack heat exchanger	20	$18.41	$1.48	5%
Duct insulation	20	$3.52	$0.28	2%
EMS install	20	$31.79	$2.55	10%
EMS optimization	5	$0.30	$0.07	1%
Process Heat Measures				
Process Controls & Management	8	$3.33	$0.51	5%
Heat Recovery	20	$92.06	$7.39	20%
Efficient burners	10	$14.27	$1.85	18%
Process integration	15	$87.04	$8.39	17%
Efficient drying	20	$61.55	$4.94	17%
Closed hood	15	$34.82	$3.35	5%
Extended nip press	20	$92.59	$7.43	16%
Improved separation processes	20	$26.30	$2.11	10%
Flare gas controls and recovery	15	$87.04	$8.39	50%
Fouling control	5	$1.77	$0.41	7%
Efficient furnaces	20	$13.89	$1.11	6%
Oxyfuel	20	$63.13	$5.07	20%
Batch cullet preheating	15	$27.85	$2.68	16%
Preventative maintenance	5	$0.30	$0.07	2%
Combustion controls	8	$5.32	$0.82	8%
Optimize furnace operations	10	$9.52	$1.23	10%
Insulation/reduce heat losses	15	$29.79	$2.87	5%

We estimated the average normalized cost of industrial energy efficiency investments to be $12.58/mmBtu saved. This estimate was arrived at by estimating the sum of the annual incremental savings for each measure in each industry based on end-use energy distribution and dividing the corresponding total investment required.

B.3.5. Potential for Energy Savings

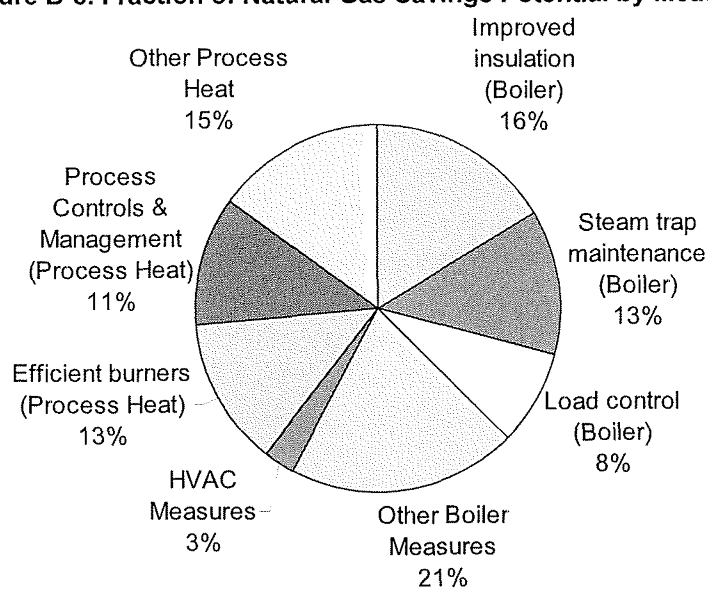
In Arkansas, a diverse set of efficiency measures will provide electricity savings for industry. The application of these measures contributes to total economic electric savings potential of 16%. These savings are distributed as presented in Figure B-4.

Figure B-4. Fraction of Electricity Savings Potential by Measure



The total natural gas savings potential for the state of Arkansas is about 17%. These savings are distributed as presented in Figure B-5.

Figure B-5. Fraction of Natural Gas Savings Potential by Measure



In addition, this analysis did not consider process-specific efficiency measures that would be applied at the individual site level because available data does not allow this level of analysis. However, based on experience from site assessments by DOE and others entities, we would anticipate an additional economic savings of 5-10%, primarily at large energy intensive manufacturing facilities. Therefore, the overall economic industrial efficiency resource opportunity for electricity and natural gas is on the order of 21-26% and 22%-27%, respectively.

Appendix C—Energy Efficiency Policy Analysis

C.1. Energy Efficiency Policy Analysis Results and Assumptions

Table C-1. Electricity Savings from the Medium Case Scenario

	Annual Electricity Savings by Policy (GWh)	2010	2015	2020	2025	Total Savings in 2025 (%)*
1	Energy Efficiency Resource Standard	87	1,498	3,393	5,375	9.8%
	Residential Programs	*21*	*286*	*769*	*973*	*1.8%*
	Commercial Programs	*40*	*515*	*1,095*	*1,451*	*2.6%*
2	*Behavioral Initiative*	*7*	*144*	*152*	*163*	*0.3%*
3	*Weatherization of Severely Inefficient Homes*	*9*	*40*	*69*	*98*	*0.2%*
4	*Manufactured Homes Initiative*	-	*5*	*12*	*20*	*0.04%*
5	*Industrial Initiative*	-	*439*	*1,114*	*1,789*	*3.2%*
6	*RD&D Initiative*	-	*7*	*69*	*723*	*1.3%*
7	*Rural and Agricultural Initiative*	*10*	*62*	*113*	*159*	*0.3%*
8	Building Energy Codes	-	208	530	1,068	1.9%
9	Combined Heat and Power	-	6	43	103	0.2%
10	Lead by Example	37	215	348	467	0.8%
	Total Savings	**124**	**1,928**	**4,314**	**7,013**	**12.7%**
	Savings from Arkansas Cooperatives	**15**	**268**	**604**	**955**	**1.7%**
	Remaining Electricity Needs (GWh)	**45,900**	**48,205**	**47,673**	**47,075**	
	Notes					
	* Percent relative to reference case forecast.					
1	An Energy Efficiency Resource Standard (EERS) would require that all electric utilities reach 1% incremental annual savings by 2014, where the annual targets would accumulate to about 14.25% savings by 2025. Incremental annual savings are a function of prior-year sales. The incremental targets are set as follows: 0.25% in 2010, 0.5% in 2011, 0.75% in 2012–2013, and 1.0% by 2014 through the remainder of the analysis. Estimated annual investment costs for utility residential and commercial programs are based on our economic potential analyses of the residential and commercial sectors, where we estimate annual investments of $0.235 and $0.14 per kWh saved for the residential and commercial sectors, respectively. Allocation of costs between customer costs and incentives are a percentage of the annual investments, split 50/50 between the two. Program and administrative costs are also a percentage of the annual investments, or 12.5% and 10% of annual investments for residential and commercial programs respectively. Costs from the individual policies that are allowed to contribute towards the EERS are also included.					
2	We assume that there are two sets of participants in the program. The first set is the total number of participants, all of whom receive monthly reports that allow them to ramp up to 2% annual savings. The second set is a subset of the total number of participants, where the installation of in-home displays in addition to the monthly reports allows this subset of participants to achieve an additional 6% savings, for a total of 8% annual savings. In the medium case scenario, we assume that 80% of households in Arkansas participate in the program. These households are able to ramp up to the minimum 2% annual savings over four years, or by 2013, which is sustained for the					

	remainder of the analysis. We then assume that our subset of participants with in-home displays, or 20% of the total number of participants (20% of 80%), is able to ramp up to 6% savings over ten years, or by 2019, which is also sustained for the remainder of the analysis. We assume that 40% of savings comes from electricity, as reported in Entergy's residential appliance survey for homes heating with electricity. Costs for the program are entirely administrative, which are based on costs from the program offered by OPOWER and are relative to the number of households participating.
3	We assume that the AWP ramps up to an annual weatherization of 1,600 homes by 2015 and sustains that annual target for the remainder of the analysis. We use the annual cost and savings estimates for the AWP taken from the July 2, 2007 filing in Docket No. 07-079-TF. The AWP estimated that annual electricity savings from weatherizing 1,100 homes would amount to 9.94 GWh at a two year program cost of $7.65 million. Costs and savings for electricity are allocated by the percent of homes heated with electricity as reported in Entergy's residential appliance survey, which was reported as 40%. Savings and costs increase proportionally with the number of homes weatherized. Through 2025, we assume about 27,000 homes in Arkansas are weatherized.
4	We assume a three-year pilot program beginning in 2010 that weatherizes 600 homes over the course of the pilot. The number of homes serviced ramps-up by 100 homes per year to 500 per year in 2015 where it remains for the period of the analysis, for a total of about 6,500 homes serviced. We assume weatherization is able to generate electricity savings of 20%. Costs are base on an existing weatherization program in South Carolina, where the total policy costs are based on an average cost of $4,000 per home.
5	The medium case scenario assumes that a manufacturing initiative achieves 25 industrial assessments in the first year, ramping up to 100 in the third and each subsequent year. The analysis assumes that each assessment identifies 15% electricity savings and that 50% of identified savings are implemented. Project costs assume the average investment cost per kWh from the industrial sector analysis ($0.23/kWh) and program cost is assumed to be 12.5% of projected cost savings to the end-user.
6	Using costs and savings data from the New York State Energy Research Development Authority, scaling it down to more closely represent Arkansas demographics (using population as a proxy) and allowing time to develop and gather funding for the initiative, we assume an RD&D facility in Arkansas begins generating savings of 3.5% in 2014, 6.5% in 2015, 10% in 2016, 15% in 2017, 25% in 2018, and 40% in 2019, where 67% of savings are from electric efficiency. Savings grow by 60% each year thereafter. We assume annual investment costs of $0.235, $0.14, and $0.23 per kWh saved for the residential, commercial, and industrial sectors, which are derived from our economic potential analyses for the various sectors. Program and administrative costs are taken from NYSERDA and scaled down to more closely reflect Arkansas using state population as a proxy.
7	This program analysis is based on similar programs and data from the State of Wisconsin Focus on Energy 2007 Semiannual Report. We assume the average cost of conserved energy is $0.025/kWh, that program & administrative costs are 24% of the cost of investment, and that customers cover half of the investment cost.
8	We assume that the 2010 IECC is adopted in 2012 and becomes effective in 2013, reducing energy consumption by 30% in new residential construction relative to the 2003 IECC. We then assume that the state energy code is updated in 2018 to achieve 50% savings beyond code (20% above the 2012 IECC), which would become effective in 2020. For the commercial sector, we assume that the Arkansas Energy Code is updated to reference ASHRAE 90.1-2010 in 2012, effective 2013. As in the residential sector, we then assume that Arkansas adopts codes in 2018 that achieve 50% savings beyond the 2003 IECC (20% above ASHRAE 90.1-2010), effective 2020. Savings apply only to end-uses covered by building codes, which are heating, cooling, ventilation, lighting, and water heating end-uses, or 50% of electricity consumption in new residential construction and nearly 65% of electricity consumption in commercial buildings. We assume that code official training, compliance surveys, and other efforts enable enforcement levels to start at 50% at the time of adoption of a new code, ramp up to 65% in the second year, and 80% in the third year and later.
9	Savings potential for CHP is based on the market potential analysis prepared by ICF Consulting. Their analysis assumes a $500 incentive per MW for CHP facilities, which we use as a proxy for quantifying removal of regulatory disincentives.
10	This policy is modeled to reflect the requirements mandated by HB 1663, so that, in existing state buildings, energy savings of 20% are realized by 2014 and 30% by 2017 using 2008 sales as a baseline (as opposed to the 2007–2008 fiscal year), and that these savings ramp-up to 50% by 2025. We also quantify the expected savings from the 10% savings requirement in all new or major-remodeled

	buildings, which we treat as 10% savings above the current Arkansas energy code. Using data from the AEO on electricity consumption in state buildings in 2007 and assuming a commercial price of $0.07 per kWh, we estimated that 7.6% of electricity consumption in the commercial sector was from state-owned buildings.

Table C-2. Summer Peak Demand Reductions from the Medium Case Scenario

Summer Peak Reductions (MW)	2010	2015	2020	2025	% Reduction
Residential	8	111	252	397	3.4%
Commercial	16	183	381	598	5.2%
Industrial	2	105	267	473	4.1%
Total Savings (MW)	**26**	**400**	**900**	**1,468**	**12.7%**
% Reduction (relative to forecast)	**0.3%**	**3.8%**	**8.2%**	**12.7%**	

Table C-3. Total Resource Costs* from the Medium Case Scenario, Electricity Only (Million 2007$)

By Policy/Program	2010	2015	2020	2025
Energy Efficiency Resource Standard	$ 3.6	$124.6	$ 304.6	$515.9
Residential Programs	*$ 0.9*	*$ 23.8*	*$ 69.0*	*$93.3*
Commercial Programs	*$ 1.7*	*$ 42.9*	*$ 98.3*	*$139.3*
Behavioral Initiative	*$ 0.3*	*$ 12.0*	*$ 13.6*	*$ 15.6*
Weatherization of Severely Inefficient Homes	*$ 0.4*	*$ 3.4*	*$ 6.2*	*$ 9.4*
Manufactured Homes Initiative	*$ -*	*$ 0.4*	*$ 1.1*	*$ 2.0*
Manufacturing Initiative	*$ -*	*$ 36.5*	*$ 100.0*	*$171.7*
RD&D Initiative	*$ -*	*$ 0.6*	*$ 6.2*	*$ 69.4*
Rural and Agricultural Initiative	*$ 0.4*	*$ 5.2*	*$ 10.1*	*$ 15.3*
Building Energy Codes	$ -	$ 17.3	$ 47.6	$102.5
Combined Heat and Power (CHP)	$ -	$ 0.5	$ 3.8	$ 9.9
Lead by Example	$ 1.5	$ 17.9	$ 31.4	$ 44.8
Total	**$ 5.1**	**$160.3**	**$ 387.2**	**$673.1**

*Note: Total Resource Costs include total investments in energy efficiency, whether made by customers or through program incentives, plus program administrative/marketing costs.

Table C-4. Natural Gas Savings from the Medium Case Scenario

	Annual Electricity Savings by Policy (BBtu)	2010	2015	2020	2025	Total Savings in 2025 (%)*
1	Energy Efficiency Resource Standard	309	4,371	10,903	17,406	10.6%
	Residential Programs	*57*	*871*	*2,909*	*3,487*	*2.1%*
	Commercial Programs	*160*	*1,752*	*4,212*	*5,089*	*3.1%*
2	*Behavioral Initiative*	*24*	*430*	*435*	*436*	*0.3%*
3	*Weatherization of Severely Inefficient Homes*	*67*	*314*	*539*	*764*	*0.5%*
4	*Manufactured Homes Initiative*	-	*1.03*	*2.72*	*4.3*	*0.003%*
5	*Industrial Initiative*	-	*967*	*2,454*	*3,942*	*2.4%*
6	*RD&D Initiative*	-	*36*	*351*	*3,686*	*2.2%*
7	*Rural and Agricultural Initiative*	-	-	-	-	*0.0%*
8	Building Energy Codes	-	648	1,623	3,148	1.9%
9	Combined Heat and Power	-	-	-	-	0.0%
10	Lead by Example	135	791	1,277	1,706	1.0%
	Total Savings	**444**	**5,810**	**13,803**	**22,260**	**13.6%**
	Remaining Natural Gas Needs (BBtu)	**156,377**	**158,168**	**148,674**	**141,660**	

Notes

* Percent relative to reference case forecast.

1 An Energy Efficiency Resource Standard (EERS) would require that all natural gas utilities reach 0.8% incremental annual savings by 2016, where the annual targets would accumulate to almost 11% savings by 2025. Incremental annual savings are a function of prior-year sales. The incremental targets begin at 0.2% in 2010 and increase by 0.1% annually until 2016, where annual targets are set at 0.8% annually and remain at that level for the remainder of the analysis. Estimated annual investment costs for utility residential and commercial programs are based on our economic potential analyses of the residential and commercial sectors, where we estimate annual investments of $59.60 and $36.85 per MMBtu saved for the residential and commercial sectors respectively. Allocation of costs between customer costs and incentives are a percentage of the annual investments, split 50/50 between the two. Program and administrative costs are also a percentage of the annual investments, or 12.5% and 10% of annual investments for residential and commercial programs respectively. Costs from the individual policies that are allowed to contribute towards the EERS are also included.

2 We assume that there are two sets of participants in the program. The first set is the total number of participants, all of whom receive monthly reports that allow them to ramp up to 2% annual savings. The second set is a subset of the total number of participants, where the installation of in-home displays in addition to the monthly reports allows this subset of participants to achieve an additional 6% savings, for a total of 8% annual savings. In the medium case scenario, we assume that 80% of households in Arkansas participate in the program. These households are able to ramp up to the minimum 2% annual savings over four years, or by 2013, which is sustained for the remainder of the analysis. We then assume that our subset of participants with in-home displays, or 20% of the total number of participants (20% of 80%), is able to ramp up to 6% savings over ten years, or by 2019, which is also sustained for the remainder of the analysis. We assume that 60% of savings comes from natural gas, as reported in Entergy's residential appliance survey for homes heating with natural gas. Costs for the program are entirely administrative, which are based on costs from the program offered by OPOWER and are relative to the number of households participating.

3	We assume that the AWP ramps up to an annual weatherization of 1,600 homes by 2015 and sustains that annual target for the remainder of the analysis. We use the annual cost and savings estimates for the AWP taken from the July 2, 2007 filing in Docket No. 07-079-TF. The AWP estimated that annual natural savings from weatherizing 1,100 homes would amount to 46.8 MMBtu at a two year program cost of $7.65 million. Costs and savings for natural gas are allocated by the percent of homes heated with natural gas as reported in Entergy's residential appliance survey, which was reported at 60%. Savings and costs increase proportionally with the number of homes weatherized. Through 2025, we assume about 27,000 homes in Arkansas are weatherized.
4	We assume a three-year pilot program beginning in 2010 that weatherizes 600 homes over the course of the pilot. The number of homes serviced ramps-up by 100 homes per year to 500 per year in 2015 where it remains for the period of the analysis, for a total of about 6,500 homes serviced. We assume weatherization is able to generate natural gas savings of 10%. Costs are base on an existing weatherization program in South Carolina, where the total policy costs are based on an average cost of $4,000 per home.
5	The medium case scenario assumes that a manufacturing initiative achieves 25 industrial assessments in the first year, ramping up to 100 in the third and each subsequent year. The analysis assumes that each assessment identifies 18% natural gas savings and that 50% of identified savings are implemented. Project costs assume the average investment cost per MMBtu from the industrial sector analysis ($13.00/MMBtu) and program cost is assumed to be 12.5% of projected cost savings to the end-user.
6	Using costs and savings data from the New York State Energy Research Development Authority, scaling it down to more closely represent Arkansas demographics (using population as a proxy) and allowing time to develop and gather funding for the initiative, we assume an RD&D facility in Arkansas begins generating savings of 3.5% in 2014, 6.5% in 2015, 10% in 2016, 15% in 2017, 25% in 2018, and 40% in 2019, where 33% of savings are from natural gas efficiency. Savings grow by 60% each year thereafter. We assume annual investment costs of $59.60, $36.85, and $13.00 per MMBtu saved for the residential, commercial, and industrial sectors, which are derived from our economic potential analyses for the various sectors. Program and administrative costs are taken from NYSERDA and scaled down to more closely reflect Arkansas using state population as a proxy.
7	We did not conduct an analysis for natural gas efficiency in the agricultural sector
8	We assume that the 2010 IECC is adopted in 2012 and becomes effective in 2013, reducing energy consumption by 30% in new residential construction relative to the 2003 IECC. We then assume that the state energy code is updated in 2018 to achieve 50% savings beyond code (20% above the 2012 IECC), which would become effective in 2020. For the commercial sector, we assume that the Arkansas Energy Code is updated to reference ASHRAE 90.1-2010 in 2012, effective 2013. As in the residential sector, we then assume that Arkansas adopts codes in 2018 that achieve 50% savings beyond the 2003 IECC (20% above ASHRAE 90.1-2010), effective 2020. Savings apply only to end-uses covered by building codes, which are heating, cooling, ventilation, lighting, and water heating end-uses, or 94% of natural gas consumption in new residential construction and nearly 60% of natural gas consumption in commercial buildings. We assume that code official training, compliance surveys, and other efforts enable enforcement levels to start at 50% at the time of adoption of a new code, ramp up to 65% in the second year, and 80% in the third year and later.
9	NA
10	This policy is modeled to reflect the requirements mandated by HB 1663, so that, in existing state buildings, energy savings of 20% are realized by 2014 and 30% by 2017 using 2008 sales as a baseline (as opposed to the 2007–2008 fiscal year), and that these savings ramp-up to 50% by 2025. We also quantify the expected savings from the 10% savings requirement in all new or major-remodeled buildings, which we treat as 10% savings above the current Arkansas energy code. Using data from the AEO on natural gas consumption in state buildings in 2007 and assuming a commercial price of $9.78 per MMBtu, we estimated that 8.7% of natural gas consumption in the commercial sector was from state-owned buildings.

Table C-5. Summary of Total Annual Costs from Efficiency Policies, Electricity and Natural Gas (Million 2007$)

By Policy/Program	2010	2015	2020	2025
Energy Efficiency Resource Standard	$ 71.6	$ 250.2	$ 269.0	$ 281.1
Residential Programs	*$ 26.1*	*$ 137.4*	*$ 144.7*	*$ 130.8*
Commercial Programs	*$ 30.6*	*$ 60.7*	*$ 61.8*	*$ (5.7)*
Behavioral Initiative	*$ 0.3*	*$ 0.5*	*$ 2.6*	*$ 3.8*
Weatherization of Severely Inefficient Homes	*$ 8.3*	*$ 5.6*	*$ 5.6*	*$ 5.6*
Manufactured Homes Initiative	*$ -*	*$ 2.0*	*$ 2.0*	*$ 2.0*
Manufacturing Initiative	*$ 0.4*	*$ 36.9*	*$ 36.9*	*$ 36.9*
RD&D Initiative	*$ 2.6*	*$ 3.8*	*$ 12.3*	*$104.9*
Rural and Agricultural Initiative	*$ 3.3*	*$ 3.4*	*$ 3.2*	*$ 2.9*
Building Energy Codes	$ -	$ 37.2	$ 41.9	$ 67.1
Combined Heat and Power (CHP)	$ -	$ 1.6	$ 1.3	$ 1.3
Lead by Example	$ 10.9	$ 9.1	$ 6.8	$ 6.8
Total	**$ 82.4**	**$ 298.0**	**$ 319.1**	**$ 356.3**

Table C-6. Electricity Savings from the High Case Scenario

	Annual Electricity Savings by Policy (GWh)	2010	2015	2020	2025	Total Savings in 2025 (%)*
1	Energy Efficiency Resource Standard	87	1,498	3,867	6,839	12.4%
	Residential Programs	*(5)*	*(53)*	*305*	*629*	*1.1%*
	Commercial Programs	*40*	*287*	*762*	*1,282*	*2.3%*
2	*Behavioral Initiative*	*33*	*256*	*271*	*290*	*0.5%*
3	*Weatherization of Severely Inefficient Homes*	*9*	*52*	*95*	*138*	*0.3%*
4	*Manufactured Homes Initiative*	-	*9*	*25*	*41*	*0.07%*
5	*Industrial Initiative*	-	*878*	*2,228*	*3,578*	*6.5%*
6	*RD&D Initiative*	-	*7*	*69*	*723*	*1.3%*
7	*Rural and Agricultural Initiative*	*10*	*62*	*113*	*159*	*0.3%*
8	Building Energy Codes	-	208	638	1,197	2.2%
9	Combined Heat and Power	-	107	623	1,012	1.8%
10	Lead by Example	37	215	398	600	1.1%
	Total Savings	**124**	**2,029**	**5,526**	**9,648**	**17.5%**
	Savings from Cooperatives	**30**	**536**	**1,375**	**2,429**	**4.4%**
	Remaining Electricity Needs	**45,885**	**47,836**	**45,689**	**42,695**	
	Notes					

	* Percent relative to reference case forecast.
1	An Energy Efficiency Resource Standard (EERS) would require that all electric utilities reach 1.5% incremental annual savings by 2021, where the annual targets would accumulate to 18% savings by 2025. Incremental annual savings are a function of prior-year sales. The incremental targets are set as follows: 0.25% in 2010, 0.5% in 2011, 0.75% in 2012–2013, 1.0% in 2014–2015, 1.25% in 2016–2020, and 1.5% through the remainder of the analysis. Estimated annual investment costs for utility residential and commercial programs are based on our economic potential analyses of the residential and commercial sectors, where we estimate annual investments of $0.235 and $0.14 per kWh saved for the residential and commercial sectors respectively. Allocation of costs between customer costs and incentives are a percentage of the annual investments, split 50/50 between the two. Program and administrative costs are also a percentage of the annual investments, or 12.5% and 10% of annual investments for residential and commercial programs respectively. Costs from the individual policies that are allowed to contribute towards the EERS are also included.
2	We assume that there are two sets of participants in the program. The first set is the total number of participants, all of whom receive monthly reports that allow them to ramp up to 2% annual savings. The second set is a subset of the total number of participants, where the installation of in-home displays in addition to the monthly reports allows this subset of participants to achieve an additional 6% savings, for a total of 8% annual savings. In the high case scenario, we assume that 90% of households in Arkansas participate in the program. These households are able to ramp up to the minimum 2% annual savings over two years, or by 2013, which is sustained for the remainder of the analysis. We then assume that our subset of participants with in-home displays, or 30% of the total number of participants (30% of 90%), is able to ramp up to 6% savings over five years, or by 2014, which is also sustained for the remainder of the analysis. We assume that 40% of savings comes from electricity, as reported in Entergy's residential appliance survey for homes heating with electricity. Costs for the program are entirely administrative, which are based on costs from the program offered by OPOWER and are relative to the number of households participating.
3	We assume that the AWP ramps up to an annual weatherization of 2,400 homes by 2010 and sustains that annual target for the remainder of the analysis. We use the annual cost and savings estimates for the AWP taken from the July 2, 2007 filing in Docket No. 07-079-TF. The AWP estimated that annual electricity savings from weatherizing 1,100 homes would amount to 9.94 GWh at a two year program cost of $7.65 million. Costs and savings for electricity are allocated by the percent of homes heated with electricity as reported in Entergy's residential appliance survey, which was reported as 40%. Savings and costs increase proportionally with the number of homes weatherized. Through 2025, we assume about 38,000 homes in Arkansas are weatherized.
4	We assume a three-year pilot program beginning in 2010 that weatherizes 600 homes over the course of the pilot. The number of homes serviced ramps-up by 200 homes per year to 1000 per year in 2015 where it remains for the period of the analysis, for a total of 13,000 homes serviced. We assume weatherization is able to generate electric savings of 20%. Costs are base on an existing weatherization program in South Carolina, where the total policy costs are based on an average cost of $4,000 per home.
5	The high case scenario assumes that a manufacturing initiative achieves 50 industrial assessments in the first year, ramping up to 200 in the third and each subsequent year. The analysis assumes that each assessment identifies 15% electricity savings and that 50% of identified savings are implemented. Project costs assume the average investment cost per kWh from the industrial sector analysis ($0.23/kWh) and program cost is assumed to be 12.5% of projected cost savings to the end-user.
6	Same as medium scenario.
7	Same as medium scenario.
8	In our high case scenario, we assume the adoption of the 2010 IECC in 2012, effective 2013. However, we build upon the medium case scenario to assume that the Arkansas Energy Code is updated in 2017 to achieve 50% savings above the 2003 IECC. We again assume that code official training, compliance surveys, and other efforts enable enforcement levels to start at 50% at the time of adoption of a new code, ramp up to 65% in the second year, and 80% in the third year and later.
9	Savings potential for CHP is based on the market potential analysis prepared by ICF Consulting. Their analysis assumes a $1000 incentive per MW for CHP facilities, which we use as a proxy for quantifying removal of regulatory disincentives.
10	Our high case scenario is also modeled to reflect the requirements mandated by HB 1663 except that increased involvement with ESCO's

	allows savings beyond the targeted dates to ramp-up more aggressively to achieve cumulative savings in existing buildings of 65% by 2025. Using data from the AEO on electricity consumption in state buildings in 2007 and assuming a commercial price of $0.07 per kWh, we estimated that 7.6% of electricity consumption in the commercial sector was from state-owned buildings. For new or major-remodeled buildings we again assume a 10% savings requirement above the current code.

Table C-7. Summer Peak Demand Reductions from the High Case Scenario

Summer Peak Reductions (MW)	2010	2015	2020	2025	% Reduction
Residential	8	68	195	374	3.2%
Commercial	16	137	345	624	5.4%
Industrial	2	209	569	956	8.2%
Total Savings (MW)	**26**	**413**	**1,109**	**2,459**	**16.9%**
% Reduction (relative to forecast)	**0.3%**	**3.9%**	**10.1%**	**16.9%**	

Table C-8. Natural Gas Savings from the High Case Scenario

	Annual Electricity Savings by Policy (BBtu)	2010	2015	2020	2025	Total Savings in 2025 (%)*
1	Energy Efficiency Resource Standard	309	4,371	12,045	20,173	12.3%
	Residential Programs	*(26)*	*(20)*	*1,735*	*2,264*	*1.4%*
	Commercial Programs	*160*	*1,249*	*3,529*	*4,478*	*2.7%*
2	*Behavioral Initiative*	*107*	*767*	*774*	*776*	*0.5%*
3	*Weatherization of Severely Inefficient Homes*	*67*	*404*	*741*	*1,078*	*0.7%*
4	*Manufactured Homes Initiative*	-	*2*	*5*	*9*	*0.005%*
5	*Industrial Initiative*	-	*1,934*	*4,909*	*7,884*	*4.8%*
6	*RD&D Initiative*	-	*36*	*351*	*3,686*	*2.2%*
7	*Rural and Agricultural Initiative*	-	-	-	-	*0.0%*
8	Building Energy Codes	-	648	1,947	3,531	2.2%
9	Combined Heat and Power	-	-	-	-	0.0%
10	Lead by Example	135	791	1,463	2,203	1.3%
	Total Savings	**444**	**5,810**	**15,455**	**25,907**	**15.8%**
	Remaining Natural Gas Needs (BBtu)	**156,377**	**158,168**	**147,022**	**138,012**	
	Notes					
	* Percent relative to reference case forecast.					
1	An Energy Efficiency Resource Standard (EERS) would require that all natural gas utilities reach 1.0% incremental annual savings by 2018, where the annual targets would accumulate to over 12% savings by 2025. Incremental annual savings are a function of prior-year sales. The incremental targets begin at 0.2% in 2010 and increase by 0.1% annually until 2018, where annual targets are set at 1.0% annually and remain at that level for the remainder of the analysis. Estimated annual investment costs for utility residential and commercial programs are based on our economic potential analyses of the residential and commercial sectors, where we estimate annual investments					

	of $59.60 and $36.85 per MMBtu saved for the residential and commercial sectors respectively. Allocation of costs between customer costs and incentives are a percentage of the annual investments, split 50/50 between the two. Program and administrative costs are also a percentage of the annual investments, or 12.5% and 10% of annual investments for residential and commercial programs respectively. Costs from the individual policies that are allowed to contribute towards the EERS are also included.
2	We assume that there are two sets of participants in the program. The first set is the total number of participants, all of whom receive monthly reports that allow them to ramp up to 2% annual savings. The second set is a subset of the total number of participants, where the installation of in-home displays in addition to the monthly reports allows this subset of participants to achieve an additional 6% savings, for a total of 8% annual savings. In the medium case scenario, we assume that 90% of households in Arkansas participate in the program. These households are able to ramp up to the minimum 2% annual savings over four years, or by 2013, which is sustained for the remainder of the analysis. We then assume that our subset of participants with in-home displays, or 30% of the total number of participants (30% of 90%), is able to ramp up to 6% savings over ten years, or by 2019, which is also sustained for the remainder of the analysis. We assume that 60% of savings comes from natural gas, as reported in Entergy's residential appliance survey for homes heating with natural gas. Costs for the program are entirely administrative, which are based on costs from the program offered by OPOWER and are relative to the number of households participating.
3	We assume that the AWP ramps up to an annual weatherization of 2,400 homes by 2010 and sustains that annual target for the remainder of the analysis. We use the annual cost and savings estimates for the AWP taken from the July 2, 2007 filing in Docket No. 07-079-TF. The AWP estimated that annual natural savings from weatherizing 1,100 homes would amount to 46.8 MMBtu at a two year program cost of $7.65 million. Costs and savings for natural gas are allocated by the percent of homes heated with natural gas as reported in Entergy's residential appliance survey, which was reported at 60%. Savings and costs increase proportionally with the number of homes weatherized. Through 2025, we assume about 38,000 homes in Arkansas are weatherized.
4	We assume a three-year pilot program beginning in 2010 that weatherizes 600 homes over the course of the pilot. The number of homes serviced ramps-up by 200 homes per year to 1000 per year in 2015 where it remains for the period of the analysis, for a total of about 6,500 homes serviced. We assume weatherization is able to generate natural gas savings of 10%. Costs are base on an existing weatherization program in South Carolina, where the total policy costs are based on an average cost of $4,000 per home.
5	The medium case scenario assumes that a manufacturing initiative achieves 50 industrial assessments in the first year, ramping up to 200 in the third and each subsequent year. The analysis assumes that each assessment identifies 18% natural gas savings and that 50% of identified savings are implemented. Project costs assume the average investment cost per MMBtu from the industrial sector analysis ($13.00/MMBtu) and program cost is assumed to be 12.5% of projected cost savings to the end-user.
6	Same as medium scenario.
7	Same as medium scenario.
8	In our high case scenario, we assume the adoption of the 2010 IECC in 2012, effective 2013. However, we build upon the medium case scenario to assume that the Arkansas Energy Code is updated in 2017 to achieve 50% savings above the 2003 IECC. We again assume that code official training, compliance surveys, and other efforts enable enforcement levels to start at 50% at the time of adoption of a new code, ramp up to 65% in the second year, and 80% in the third year and later.
9	NA
10	Our high case scenario is also modeled to reflect the requirements mandated by HB 1663 except that increased involvement with ESCO's allows savings beyond the targeted dates to ramp-up more aggressively to achieve cumulative savings in existing buildings of 65% by 2025. Using data from the AEO on natural gas consumption in state buildings in 2007 and assuming a commercial price of $9.78 per MMBtu, we estimated that 8.7% of natural gas consumption in the commercial sector was from state-owned buildings. For new or major-remodeled buildings we again assume a 10% savings requirement above the current code.

C.2. Detailed Information on State Energy Efficiency Resource Standards

* Combined RES/EERS
**Pending
*** Voluntary Standard

Table C-9. Annual State Energy Efficiency Resource Standards

State	Cumulative 2020	Notes
Arizona	15.28%	Electric Energy Efficiency Rules, approved by the ACC Dec. 19, 2009. Targets total 20% savings by 2020 relative to 2005 sales. Approved by the ACC Dec. 18, 2009.
Arkansas	1.5%	Approved by the APSC Dec. 10, 2010. Over three years, targets are 1.5% cumulative for electric, 0.9% for natural gas.
California	12.82%	2010–2013 goals from Proposed Decision Application 08-07-021 et al., Aug. 25, 2009; 2014–2020 goals from Table 2, Rulemaking 06-04-010; Decision 08-07-047. July 31, 2008
Colorado	11.49%	Based on GWh targets established for Public Service Co. and Black Hills
Connecticut	17.50%	Based on plans filed by utilities in response to legislation requiring acquisition of all cost-effective efficiency savings.
Delaware	15.00%	Established by SB 106 (7/29/2009); Del. Code, Title 25 Sec. 1502
Hawaii	13.69%	Total annual 4,300 GWh saved by 2030 (HB 1464); percentages are for 2020, estimated based on 2030 GWh savings target
Illinois	18.00%	Under the Illinois Power Agency Act, utilities are responsible for achieving 75% of energy-saving targets with the Indiana Department of Commerce and Economic Opportunity saving the remaining 25%. Targets slowly ramp up, reaching 2% savings and continuing at that level thereafter.
Indiana	13.81%	Ordered savings percentages are of 3 prior years' average sales. See Cause No. 42693, Phase II Order, Dec. 9, 2009.
Iowa	6.30%	Estimates of savings for three IOUs from "Energy Efficiency in Iowa's Electric and Natural Gas Sectors" Report to the Iowa General Assembly (January 1, 2009).
Maryland	14.51%	As legislated, Maryland is required to achieve 15% energy savings by 2015 relative to 2007 sales.
Massachusetts	26.10%	EE Programs agreement by Governor's office and attorney general, approved by Energy Efficiency Advisory Council, October 7, 2009. Pending DPU approval.
Michigan	10.55%	Savings begin at 0.3%, ramping up to 1%/year by 2012 and thereafter; SB 295

Minnesota	16.50%	As legislated, percent savings (1.5% annually) is relative to average of prior 3 years' sales.
Nevada*	3.76%	EE may meet up to 25% of the RPS which is set at 25% by 2025.
New Mexico	8.06%	10% of 2005 sales by 2020, or about 8% relative to 2019 (prior year) sales.
New York	15.25%	Annual MWh targets are set to achieve 15% of statewide sales by 2015 (see CASE 07-M-0548, June 23, 2008).
North Carolina*	2.92%	RES: 3% in 2012, 6% in 2015, 10% in 2018, 12.5% in 2021 and thereafter. EE may meet up to 25% of RES until 2021 and 40% of the RES thereafter.
Ohio	12.13%	22.2% by 2025 relative to 3 prior years' average sales, beginning with 0.3% savings in 2009, ramping up to 1% per year by 2014, and jumping to 2%/year in 2019 through 2025. See Ohio Revised Code Chapter 4928.66
Pennsylvania	2.98%	Savings are set at 1% of 2009–2010 sales in 2011 and 3% of 2009–2010 sales in 2013 with targets post-2013 still to be set by the Commission.
Rhode Island	3.44%	Docket 3931, savings estimates for 2009–2011 of about 1.15% of prior year's sales. We assume this level of savings continues through 2020.
Texas	4.08%	According to the Census Bureau, the Texas population will increase by 18.2% between 2010 and 2020. Assuming an annual growth rate of about 1.7% per year and a savings target of 20% reduced load growth, annual targets are about 0.34% each year.
Utah**	11.00%	HJR 9 urges the PUC to approve programs to reach savings of not less than 1% per year annually.
Vermont	7.78%	Required savings are 360,000 MWh for 2009–2011.
Virginia***	7.86%	State legislation sets goal of 10% reduction in 2006 sales by 2022.
Wisconsin	13.50%	Approved by the PSCW Nov. 9, 2010 in Docket # 5-GF-191. Targets start in 2011 at 0.75% for electric, 0.50% for natural gas, ramping up to 1.50% and 1.00% by 2014 and years thereafter.
Washington	11.74%	Law requires savings targets based on the Northwest Power Plan. The Draft 6th Northwest Power Plan estimates 52,000 MWh in potential savings by 2030 under various conservation scenarios. This would be about 20% of 2030 sales or about 1% savings annually.

Notes: Percentages derived from legislated/regulated targets relative to the prior year's IOU sales. Projected sales derived from actual 2007 IOU sales (EIA-861) and AEO 2009 regional growth rates (except for Texas' rate, which is from the US Census Bureau).

Appendix D—Demand Response Analysis

D.1. Introduction

This report defines Demand Response (DR), assesses current DR activities in Arkansas, identifies policies in the state that impact DR, uses benchmark information to assess DR potential in Arkansas, and identifies barriers in the state that might keep DR contributing appropriately to the resource mix that can be used to meet electricity needs. The analysis concludes with identification of policy recommendations regarding DR.

Objectives of this Assessment

This assessment develops estimates of DR potential for Arkansas. Potential load reductions from DR are estimated for the residential, commercial, and industrial sectors (see Section 3). The assessment also includes discussions of reductions possible from other DR programs, such as DR rate designs (see Section 3.6).

Role of Demand Response in Arkansas's Resource Portfolio

The DR capabilities developed by Arkansas utilities will become part of a resource strategy that includes resources such as traditional generation resources, renewable energy, power purchase agreements, options for fuel and capacity, energy efficiency and load management programs. Objectives include meeting future loads at lower cost, diversifying the portfolio to reduce operational and regulatory risk, and allow Arkansas customers to better manage their electricity costs. The growth of renewable energy supply (and plans for increased growth) can increase the importance of DR in the portfolio mix. For example, sudden renewable energy supply reductions (e.g., from an abrupt loss in wind) may be mitigated quickly with DR.

Summary of DR Potential Estimates in Arkansas

Table D-1 shows the resulting cumulative load shed reductions possible for Arkansas, by sector, for years 2015, 2020, and 2025. Load impacts grow rapidly through 2018 as program implementation takes hold. After 2018, the program impacts increase at the same rate as the forecasted growth in peak demand.

The high scenario DR load potential reduction is within a range of reasonable outcomes in that it has an eleven year rollout period (beginning of 2010 through the end of 2020), providing a relatively long period of time to ramp up and integrate new technologies that support DR. A value nearer to the high scenario than the medium scenario would make a good MW target for a set of DR activities.

The high scenario results show a reduction in peak demand of 639 MW is possible by 2015 (6.1% of peak demand); 1,322 MW is possible by 2020 (12.1% of peak demand); and 1,360 MW is possible by 2025 (11.8% of peak demand).

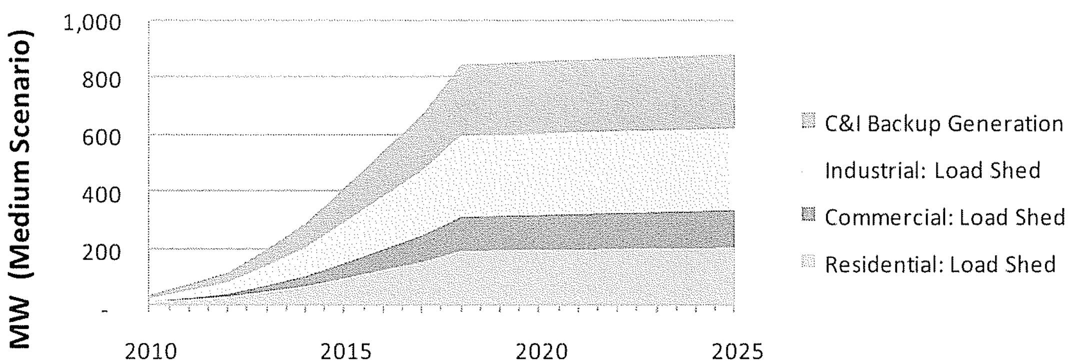
The more conservative medium scenario results show a reduction in peak demand of 412 MW is possible by 2015 (3.9% of peak demand); 853 MW is possible by 2020 (7.8% of peak demand); and 877 MW is possible by 2025 (7.6% of peak demand).

Table D-1. Summary of Potential DR in Arkansas, by Sector, for Years 2015, 2020, and 2025

	Low Scenario			Medium Scenario			High Scenario		
	2015	**2020**	**2025**	**2015**	**2020**	**2025**	**2015**	**2020**	**2025**
Load Sheds (MW):									
Residential	55	116	120	92	193	201	129	271	281
Commercial	22	47	51	59	127	136	110	237	256
Industrial	62	125	125	140	281	280	248	500	498
C&I Backup Generation (MW)	91	189	195	121	251	260	152	314	325
Total DR Potential (MW)	230	477	491	412	853	877	639	1,322	1,360
DR Potential as % of Total Peak Demand	2.2%	4.4%	4.3%	3.9%	7.8%	7.6%	6.1%	12.1%	11.8%
a. See Section 3 for underlying data and assumptions.									

Figure D-1 shows the resulting load shed reductions possible for Arkansas, by sector, from year 2010, when load reductions are expected to begin, through year 2025.

Figure D-1. Potential DR Load Reductions in Arkansas by Sector (Medium Scenario)



These estimates reflect the level of effort put forth and utilities are recommended to set targets for the high scenarios. These estimates are based on assumptions regarding growth rates, participation rates, and program design. These factors are discussed further in this Appendix. In developing these DR potential estimates, the integration of DR with select energy efficiency activities was considered to help ensure that load impacts were not double counted. The estimated load reduction per program participant is conservatively estimated to account for increased energy efficiency in the future.

D.2. Defining Demand Response

DR focuses on shifting energy from peak periods to off-peak periods and clipping peak demands on days with the highest demands. Within the set of demand-side options, DR focuses on clipping peak demands that may allow for the deferral of new capacity additions, and it can enhance operating reserves available to mitigate system emergencies. Energy efficiency focuses on reducing overall energy consumption with attendant permanent reductions in peak demand growth. Taken together, these two demand-side options can provide opportunities to more efficiently manage growth, provide customers with increased options to manage energy costs, and develop least cost resource plans.

DR is an increasingly important tool for resource planning as power plant siting has grown more difficult and the costs of peak power have increased. Through development of DR capability, utilities can complement existing energy efficiency programs with a set of offerings that provide, at a minimum, 1) enhanced reliability, 2) cost savings, 3) reduced operating risk through resource diversification, and 4) increased opportunities for customers to manage their electric bills.

DR resources are usually grouped into two types: 1) load-curtailment activities where utilities can "call" for load reductions; and 2) price-based incentives which use time-differentiated and/or dispatchable rates to shift load away from peak demand periods and reduce overall peak-period consumption. Interest in both types of DR activities has increased across the country as fuel input prices have increased, environmental compliance costs have become more uncertain, and investment in overall electric infrastructure is needed to support new generation resources.

The mechanisms that utilities may use to achieve load reductions can range from voluntary curtailments to mandatory interruptions. These mechanisms include, but are not limited to:

- Direct load control by the utility using radio frequency or other communications platforms to trigger load devices connected to air conditioners, electric water heaters, and pool pumps;
- Manual load curtailments at commercial and industrial (C&I) facilities, including shutting off production lines and dimming overhead lighting;
- Automated DR ("Auto-DR") technologies utilizing controls or energy management systems to reduce major C&I loads in a pre-determined manner (e.g., raising temperature set points and reducing lighting loads); and
- Behavior modifications such as raising thermostat set points, deferring electric clothes drying in homes, and reducing lighting loads in commercial facilities.

D.3. Rationale for Demand Response

DR alternatives can be implemented to help ensure that a utility continues to provide reliable electric service at the least cost to its customers. Specific drivers often cited for DR include the following:

- **Ensure reliability**—DR provides load reductions on the customer side of the meter that can help alleviate system emergencies and help create a robust resource portfolio of both demand-side and supply-side resources that help meet reliability objectives.

- **Reduce system costs**—DR may be a less expensive option per megawatt than other resource alternatives. DR resources compete directly with supply-side resources and other resource investments in many regions of the country. Portfolios that help lower the increase in customers' expenditures on electricity over time represent an increasingly important attribute from the perspective of many energy customers.

- **Manage operational and economic risk through portfolio diversification**—DR capability is a resource that can diversify peaking capabilities. This creates an alternative means of meeting peak demand and reduces the risk that utilities will suffer financially due to transmission constraints, fuel supply disruptions, or increases in fuel costs.

- **Provide customers with greater control over electric bills**—DR programs would allow customers to save on their electric bills by shifting their consumption away from higher cost hours and/or responding to DR events. The ability to manage increases in energy costs has increased in importance for both residential and commercial customers. Standard residential and commercial tariffs provide customers with relatively few opportunities to manage their bills.

- **Address legislative/regulatory interest in DR**—In January 2007, the Arkansas Public Service Commission issued an Order establishing "Guidelines on Resource Planning for Electric Utilities," which require utilities to consider all generation, transmission, and DR options in the region. Specifically, these guidelines direct utilities to "give 'comparable consideration' to demand and supply resources and to assess 'all reasonably useful and economic supply and demand resources that may be available to a utility or its customers,' and to identify and investigate resources including 'energy efficiency, conservation, demand-side management, interruptible load, and price responsive demand.'" The Commission decided not to adopt PURPA Standard 14

("Time-Based Metering and Communications") because it indicated that it can best foster the "the development of various Demand Response technologies and practices" through "utility-specific rate or tariff proceedings."

DR is gaining greater acceptance among both utilities and regulators in the United States. A 2006 FERC survey found that 234 "entities" were offering direct load control programs and the FERC's assessment noted that "there has been a recent upsurge in interest and activity in DR nationally and, in particular, regional markets" (FERC 2006).[57] The recent proliferation of DR offerings has been promoted in part by utilities hoping to reduce system peaks while offering customers more control over electric bills and in part by regulators. Although federal legislation has not been the driver behind the trend, it is one of many indications, at all levels of government and industry, of the growing support for DR.[58]

Many states experience significant reductions in peak demand from Demand-Side Management (DSM) programs (which include DR programs). Regulatory filings show that California experienced 495 MW in peak demand reductions in 2005 (1% of total peak demand); New York experienced 288 MW reductions in 2005 (1% of total peak demand); and Texas experienced 181 MW in reductions in 2005 (1% of total peak demand) from DSM programs. These results are annual values that do not consider the cumulative (i.e., year-to-year) impacts that accrue over the lifetimes of the conservation measures. Therefore, cumulative percentage reductions in peak demand are much higher than the annual figures stated.

D.4. Assessment Methods

As has been shown in numerous other jurisdictions across America, well-designed DSM programs incorporating DR strategies represent an effective and affordable option for reducing peak demand and meeting growing demand for electricity. This effort estimated conservative peak demand reduction for South Carolina using local energy use characteristics, demographics, and forecast peak demand, assuming relatively basic DR strategies comprising responsive reductions in demand. The following research approach was used to conduct the analysis:

- Review of existing information regarding Arkansas' customer base including:
    - Customer counts and average annual energy consumption by market segment;
    - Forecasts of future energy consumption and customer counts by market segment;
    - Previous DSM planning and potential studies.

- Review of additional publicly-available secondary sources including:
    - U.S. DOE's Commercial Building Energy Consumption Survey (CBECS) and Residential Energy Consumption Survey (RECS) data;
    - Previous studies relevant to the current effort completed by Summit Blue in other regions as well as entities in other jurisdictions.

[57] The FERC report uses the term "entities" to refer to all types of electric utilities, as well as organizations such as power marketers and curtailment service providers.

[58] The federal Energy Policy Act of 2005 (EPAct) directs the Secretary of Energy to "identify and address barriers to the adoption of demand response programs," and the Act declares a U.S. policy in support of "State energy policies to provide reliable and affordable demand response services." EPAct directed FERC to conduct its survey of DR programs and also directed the U.S. Department of Energy to report on the benefits of DR and how to achieve them. Separately, a *National Action Plan for Energy Efficiency,* which advocates DR and other efficiency efforts, was developed by more than 50 U.S. companies, government bodies, and other organizations, including co-chairs Diane Munns, President of NARUC and Jim Rogers, President and CEO of Duke Energy. Other utility industry members of the Leadership Group included Southern Company, AEP, PG&E, TVA, PJM Interconnection, ISO New England, and the California Energy Commission.

- Development of baseline profiles for residential and commercial customers. These profiles include current and forecast numbers of customers by market segment and electricity use profiles by segment.

- Incorporation of ACEEE baseline data and reference case into analysis.

- Obtaining state-level data when possible and estimation of information for the State of Arkansas, when state-level data was not available.

- Development of a spreadsheet approach for estimating peak demand reduction potential associated with the DR programs/technologies deemed to be most applicable to Arkansas. Estimates are developed for three scenarios—low, medium and high case scenarios.

- Conference calls with ACEEE staff and industry professionals to discuss assessment processes and legislative, regulatory, and other factors specific to the State of Arkansas.

- Incorporation of all sources of information and references into report, noting on each figure the source of the information.

- Revision of draft report based on comments from ACEEE, industry specialists and utility commenters.

D.5. State of Arkansas—Background

A sound strategy for development of DR resources requires an understanding of Arkansas's demand and resource supply situation, including projected system demand, peak-day load shapes, and existing and planned generation resources and costs.

Arkansas utilities serves a population of over 2.9 million, and generates approximately 53.3 million megawatt hours of electricity, that had a system peak load of almost 8,600 MW in 2007 (ACEEE base case for Arkansas). Electricity demand has grown an average of 3% per year since 1990, fluctuating moderately (EIA 2009).

Arkansas has been and likely will continue to be a modest importer of energy and likewise be dependent on out-of-state capacity. Coal-fired plants in Arkansas supply about one-half of State electricity demand and rely entirely on coal deliveries via railcar from Wyoming (EIA 2009).

Just over half of the total sales in Arkansas are attributed to 2 retailers: Entergy Arkansas Inc., and Southwestern Electric Power Company (SWEPCO). The five largest electricity retailers in Arkansas are the following entities, with percent contribution in parentheses:

- 1. Entergy Arkansas Inc (45%)
- 2. Southwestern Electric Power Co (9%)
- 3. Mississippi County Electric Coop (7%)
- 4. Oklahoma Gas & Electric Co (6%)
- 5. First Electric Coop Corp (4%)

D.5.1. Assessment of Utility DR Activities

This section outlines existing DR programs offered to customers in Arkansas, by utility.

Entergy Arkansas Inc.

Entergy offers time-of-use rates to its residential customers to encourage reduction of electricity usage during peak hours.

Entergy's "Large Commercial & Large Industrial Demand Response Program" consists of programs that encourage a change in energy use by a customer from normal consumption patterns in response to changes in the price of energy over time. The Arkansas Public Service Commission (APSC) has recognized Entergy Arkansas, Inc.'s Optional Interruptible Service Rider (OISR), Large General Service Time-of-Use Rate Schedule (GST) and Large Power Service Time-of-Use Rate Schedule (PST) as DR program tools to help customers review their current usage patterns and determine if they have opportunities to change their consumption patterns.

- Under OISR a customer that has 100 kW or more of load that they are willing to interrupt at times of high electric system may benefit by contracting for a portion of their load to be taken under OISR. Should they fail to interrupt for any reason when an interruption is requested a penalty charge will be assessed.
- TOU rates may be beneficial for high-load-factor customers or customers that can and will make changes in their process to utilize more demand and energy during off-peak periods.

Entergy has Account Service Managers available to work with customers and the Entergy Arkansas* Rate Design and Administration group to analyze if any of these rate schedules may be beneficial to a customer.

Entergy's goal for 2008 was to sign up 3 MW of load and 1,160 MWh of energy under their DR programs, and an additional 3 MW and 1,160 MWh in 2009 (EAI 2010a).

Southwestern Electric Power Company (SWEPCO)

SWEPCO's parent company is American Electric Power (AEP). SWEPCO offers two DR tariffs and one DR program in their Arkansas jurisdiction. One tariff is available in conjunction with SWEPCO's Lighting and Power (LP) or Large Lighting and Power (LLP) rate schedules (SWEPCO 2009a). Another tariff is a Time-of-Use (TOU) Tariff.

The "Load Management Standard Offer Program" (LM SOP) is a DR program targeted to Commercial and Industrial customers served by SWEPCO with a minimum peak electric demand of 250 kW or greater. Monetary incentives are paid to customers that are capable of interrupting electrical load within a customer facility on a one-hour advance notice basis. Each customer contracts annually with SWEPCO for a certain amount of interruptible electric load (expressed in kilowatts, or kW) available at a customer's facility when SWEPCO calls upon the customer to do so. The minimum contract amount is 250 kW of interruptible load per customer. The contracted electrical load will be interrupted by the customer at the time(s) so designated and for the duration of time(s) so designated by SWEPCO. SWEPCO does not directly control the load interruption. The LM SOP is marketed to the following sample of general customer categories:

- Pulp and Paper Mills
- Industrial Fabrication Facilities
- Medical and Hospital Facilities
- Freezer and Cold Storage Plants
- Municipal Water and Wastewater Treatment Plants

The program had 2009 expected savings of 245,000 kWh and demand savings of 5,000 kW (SWEPCO 2009b).

SWEPCO currently does not have any Direct Load Control (DLC) programs and does not have anything available for the residential or small commercial sectors (Personal Communication, Phillip Watkins, Consumer Programs Manager, SWEPCO, March 4, 2010).

Oklahoma Gas & Electric Co (OG&E)

OG&E offers DR programs which are either event based or price response driven. This section summarizes these programs as described in their Integrated Resource Plan (OG&E 2010). Event based programs are initiated by OG&E in response to varying external stimuli. Price response programs are tariffs with predefined, recurring pricing.

OG&E manages three event based programs that are available as voluntary riders for larger commercial and industrial customers to reduce their load during peak loading periods:

- Curtailment Rider (CR-1)
- Interruptible Rider (IR-1)
- Performance Award for Curtailed Energy (PACE-1)

OG&E offers 9 tariffed price response programs. These programs are designed to encourage customers to permanently shift usage on the distribution system from high production cost (peak) hours to lower production cost (off-peak) hours. Eight of the tariffs are focused specifically at summer seasonal peak hours use. The Real Time Pricing tariff focuses on all hours of the year.

- Residential—Time of Use
- General Service—Time of Use
- Power and Light—Time of Use
- Public Schools—Demand*
  - Standard TOU
  - Compressed TOU
- Public Schools—Non Demand* 2007 19.1 0.13
  - Standard TOU
  - Compressed TOU
- Oil & Gas Producers
- Real Time Pricing (RTP)-DAP

Seven of these programs are time-of-use programs. Time-of-use programs are seasonally and time-differentiated programs that communicate varying prices to customers signaling them to shift their energy use habits. A higher price signal for energy usage during the summer season (June 1st through September 30th) on-peak hours (between 2:01 pm and 7:00 pm) encourages customers to shift usage to off-peak hours (lower priced hours). These time-of-use programs brought about 20,200MW reductions in peak demand in 2008.

OG&E has two new programs for DR:

- Real Time Pricing (DR-RTP) and the distribution automation program Integrated Voltage
- VAR Control (DA-IVVC).

DR-RTP utilizes a Home Area Network (HAN), which is an internet based web application that will be made available to all customers free of charge. This system will provide customers with near real time information on their energy consumption, cost to date, current price, and assumed cost. It will provide guidance and tips on how to manage and reduce their bill, as well as provide comparisons to other comparable homes. Other key components of the HAN are the communication devices of the network within a premise. The purpose is to allow communication to in home devices; primarily Programmable Communicating Thermostats (PCT) or In Home Displays (IHD). The HAN could eventually communicate to other devices like intelligent appliances, Plug-in Hybrid Electric Vehicle (PHEV), or wall plugs for control of any device. A PCT is capable of accepting commands over the HAN, which allows the remote manual or automatic adjustment of temperature based on personal preferences or pricing signals. For example, a consumer could choose to set a lower temperature setting on their air conditioner that would automatically be set based on a Peak Price signal. This setting could potentially be set directly on the

PCT or remotely programmed through a customer web portal. Customers will have override capability of this feature. This thermostat may also serve as the in-home display panel described below. An IHD operates the same as a PCT except that they have no control capability. The purpose of the IHD is to send information to the consumer for the purpose of eliciting demand response actions or energy conservation. This display provides continuous feedback on energy cost, which improves customer awareness and effectiveness of the price signals. This information could consist of price signals, historic usage as compared to other customers, or usage month to date. Field tests have indicated that this technology is highly effective in influencing energy consumption patterns.

DA-IVVC allows reactive and voltage control elements on the circuit to be operated in a coordinated fashion to reduce the voltage profile or reactive power requirements along the feeder. The ability to reduce peak demand and minimize line losses using this technology are important considerations.

Over the next ten years, OG&E is planning for 20% of the residential customers to adopt the in home devices, each reducing their energy consumption during OG&E system peak hours by 1.3 kW. Likewise, over the next ten years, the distribution automation program will reduce OG&E system peak load by more than 50 MW.

OG&E will expand Smart Grid technology on the OG&E distribution system and in customers' homes. OG&E will also decrease peak demand through terminating existing wholesale contracts as they expire. This results in a reduction of load responsibility that is necessary to achieve their 2020 Plan and will not need to add fossil fuel generation during the next 5 years.

Electric Cooperatives of Arkansas

The Electric Cooperatives of Arkansas, consisting of Arkansas Electric Cooperative Corporation ("AECC") and its seventeen member cooperatives, have been aggressive and successful in offering and implementing DR programs, with a firm load of 2,000 MW, plus another 700 MW available for interruption (AECC 2010a). The ratio of interruptible demand to total potential demand (actual firm demand plus potential interruptible demand) is approximately 27%. The ratio of interruptible demand to firm demand is approximately 37%. The Electric Cooperatives state that they do not know of another electric utility system in the nation with a higher ratio of demand response to load (Personal Communication, Forest Kessinger, Manager, Rights and Forecasting, March 4, 2010).

The Electric Cooperatives' success in demand response has been achieved through many years of steady effort. In 1978, certain member cooperatives began using clock timer switches to control water heaters and irrigations loads. Clock switches were eventually replaced by radio-controlled load switches. As demand response became more prevalent, a statewide System Control and Data Acquisition ("SCADA) system was installed to provide the Electric Cooperatives with more sophisticated and timely load data. The receipt of virtually instantaneous data allowed the Electric Cooperatives to more surgically direct their demand response efforts.

The Electric Cooperatives continue to maintain their state-of-the-art approach to demand response by using the Internet to directly provide participating commercial and industrial ('C&I"> retail consumers with current, minute-by-minute, AECC load data. This data allows participating C&I consumers to better choose how to operate their businesses during peak summer periods.

To encourage demand response, the Electric Cooperatives have maintained rates and charges that closely adhere to their cost of service. These rates and charges provide the economic incentives for retail consumers to voluntarily participate in demand response.

While each member cooperative may have certain terms and conditions that are specific to their DR offerings, and not every member cooperative offers both Category 1 and Category 2 DR, all of the Electric Cooperatives' DR offerings fall within three basic categories:

- Member Co-op Direct Control (120 MW)

- Member Co-op C&I Voluntary Peak Avoidance (65 MW)
- AECC Controlled Industrial Loads (520 MW)

The Mississippi County Electric Cooperative

The Mississippi County Electric Coop does not offer DR programs to residential customers, but does offer a few programs to commercial and industrial customers. They do not have Time-of-Use rates, but for irrigation customers they have a Load Management Program where customers may be asked to shut down operations for reduced rates. Industrial customers may also shift operations for an incentive through their Tariffs Program (Personal Communication, Brad Harrison, Chief Operating Officer, Mississippi County Electric Coop, March 4, 2010).

D.5.2. Summary of DR Programs in Arkansas Offered to Commercial and Industrial Customers

Table D-2 summarizes the DR programs offered to Arkansas's Commercial and Industrial (C&I) customers, and displays the load reductions achieved in 2007 from these programs.

Table D-2. Summary of DR Programs in Arkansas Offered to C/I Customers

Name	Ownership	Program	Customers Enrolled (#)	MW Enrolled	Actual Peak Reductions in 2008 (MW)
Entergy Arkansas	IOU	Time of use	408	331.9	0
Entergy Arkansas	IOU	Time of Use	559	858.3	0
Entergy Arkansas	IOU	Optional Interruptible and Irrigation Direct Load Control	532	210	0
North Little Rock Electric Department	Muni	Large Customer TOU	4	5.8	0
Ozarks Electric Cooperative Corp	Coop	Large Power Off-Peak	19	14	11
Mississippi County Electric Cooperative, Inc.	Coop	Load Management: Direct control of irrigation accounts	387	13	10
Carroll Electric Cooperative Corporation	Coop	Rate 14: Interruptible	13	22.892	5.417
Conway Corporation	Muni	Optional Interruptible: Peak Shaving, customers respond when notified to run customer owned generation	2	10	8.5
Entergy Arkansas	IOU	EER: Utility bid price curtailable rates	0	331.9	0
Entergy Arkansas	IOU	EER: Utility bid price curtailable rates	0	858.3	0
First Electric Cooperative Corporation	Coop	Sch 14 Customer Managed Interruptible Credit	3	6	2
First Electric Cooperative Corporation	Coop	Sch 16 Industrial Power Optional Interruptible (when supplier declares a system emergency)	2	39	0
South Central Arkansas Electric Cooperative, Inc.	Coop	INDO: Rate Tariff	4	8.1	0

Source: Summit Blue Consulting, Forthcoming

D.5.3. Assessment of Current State Policies Affecting DR

In January 2007, the Arkansas Public Service Commission issued an Order establishing "Guidelines on Resource Planning for Electric Utilities," which require utilities to consider all generation, transmission, and DR options in the region. Specifically, these guidelines direct utilities to "give 'comparable consideration' to demand and supply resources and to assess 'all reasonably useful and economic supply and demand resources that may be available to a utility or its customers,' and to identify and investigate resources including 'energy efficiency, conservation, demand-side management, interruptible load, and price responsive demand.'" (DRCC 2009)

Section 1252 of the Energy Policy Act of 2005 (EPACT) includes demand side management provisions (in the form of a new PURPA Standard on Demand Response and Advanced Metering) and directed States and other bodies with authority over utilities to determine whether utilities under their jurisdiction to implement such. In August 2007, the Commission decided not to adopt PURPA Standard 14 ("Time-Based Metering and Communications") because it indicated that it can best foster the "the development of various Demand Response technologies and practices" through "utility-specific rate or tariff proceedings." In the course of the proceeding to consider EPACT 1252, utilities filed and the Commission approved "quick start and/or pilot" efficiency programs to run through 2009, some of which include DR. By way of further evidence of giving due consideration to EPACT 1252, the Commission noted that it issued "Guidelines on Resource Planning for Electric Utilities" in a related proceeding through which it addresses demand response and metering. Specifically, these guidelines direct utilities to "give 'comparable consideration' to demand and supply resources and to assess 'all reasonably useful and economic supply and demand resources that may be available to a utility or its customers,' and to identify and investigate resources including 'energy efficiency, conservation, demand-side management, interruptible load, and price responsive demand'" (DRCC 2009).

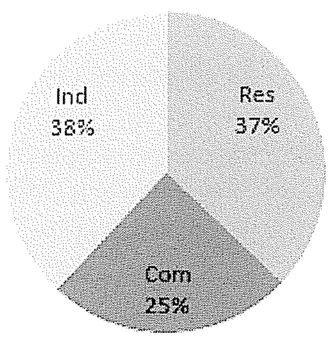
To consider adoption of PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005, the Tennessee Regulatory Authority held separate proceedings for utilities. Ultimately, in each of the proceedings the Tennessee Regulatory Authority decided not to adopt PURPA Standard 14. In January 2007, the Tennessee Regulatory Authority determined that Entergy Arkansas's rates and services already met the standard set by EPACT 1252 so there was no need to adopt it (DRCC 2009).

Many states have put in place renewable portfolio standards (RPS) to ensure that a minimum amount of renewable energy is included in the portfolio of the electricity resources serving a state. Many RPS include demand side options among the means by which the standards can be met. However, Arkansas does not currently have a RPS.

D.5.4. Energy and Peak Demands

Use of energy in Arkansas is distributed to end use categories as follows: 37% residential, 25% commercial, and 38% industrial sectors (see Figure D-2).

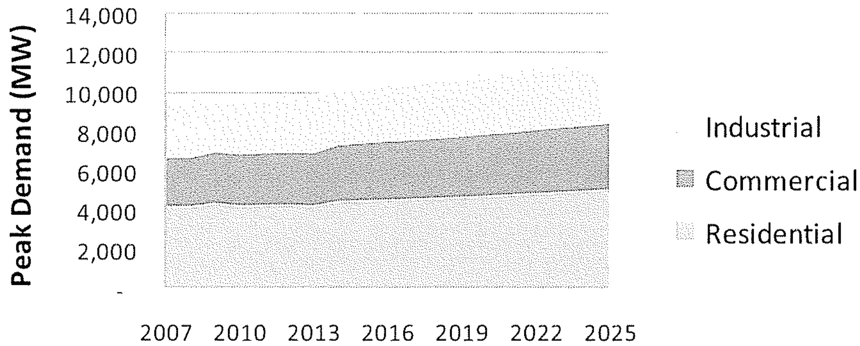
Figure D-2. Energy Sales in Arkansas by Sector (2007)



Source: ACEEE Arkansas Reference Case

In 2007, the total summer peak load was 9,721 MW and is projected to grow an average of 0.95% per year through 2025. Figure D-3 displays peak demand by sector. In 2007, residential peak demand was estimated at 4,097 MW; commercial was 2,545 MW; and industrial was 3,078 MW.

Figure D-3. Peak Demand by Sector in Arkansas



Source: ACEEE Arkansas Reference Case

D.5.5. Smart Grids and Advanced Metering Infrastructure (AMI)

The EPACT provisions for DR and Smart Metering have lead to a number of states and utilities piloting and implementing a Smart Grid, or sometimes referred to as Advanced Metering Infrastructure (AMI).

Smart Grid is a transformed electricity transmission and distribution network or "grid" that uses robust two-way communications, advanced sensors, and distributed computers to improve the efficiency, reliability and safety of power delivery and use. For energy delivery, the Smart Grid has the ability to sense when a part of its system is overloaded and reroute power to reduce that overload and prevent a potential outage situation. The end user is equipped with real-time communication between the consumer and utility allowing optimization of a consumer's energy usage based on environmental and/or price preferences (for example, critical peak pricing and time of use rates).

AMI provides:

- Two-way communication between the utility and the customer through the customer's smart meter.
- More efficient management of customer outages (location, re-routing).
- More accurate meter reading (minute, 15 minute intervals).
- More timely collection efforts (real time).
- Improved efficiency in handling service orders.
- More detailed, timely information about energy use to help customers make informed energy decisions (real time).
- Ability to reduce peak demand.
- More innovative rate options and tools for customers to manage their bills.

Smart Energy Pricing provides:

- Incentives to customers to shift energy away from critical peak periods
- The ability to for customers to save on their electricity bills.
- Lower wholesale prices for capacity and transmission—in the longer term.
- Improved electric system reliability, as demand is moderated.
- Potential to defer new transmission and generation.

The Smart Grid is comprised of multiple communication systems and equipment, which interoperability is crucial. Not all communication protocols are applicable to every utility's geography; therefore, pilots are essential in testing the equipment and communication software for various geographies. Furthermore, the identification of those geographic regions with the best return on investment during a pilot will aid the staged implementation plan. Standards are continuing to be researched through organizations including: 1) IntelliGrid—Created by the Electric Power Research Institute (EPRI); 2) Modern Grid Initiative (MGI) is a collaborative effort between the DOE, the National Energy Technology Laboratory (NETL), utilities, consumers, researchers, and other grid stakeholders; 3) Grid 2030—Grid 2030 is a joint vision statement for the U.S. electrical system developed by the electric utility industry, equipment manufacturers, information technology providers, federal and state government agencies, interest groups, universities, and national laboratories; 4) GridWise—a DOE Office of Electricity Delivery and Energy Reliability (OE) program; 5) GridWise Architecture Council (GWAC) was formed by the DOE; and 6) GridWorks—A DOE OE program.

Principal benefits of Smart Grid technologies for DR include increased participation rates and lower costs. In 2009, Dominion plans to deploy 200,000 smart meters as part of a large demonstration program of smart grid technology in urban and rural areas of Dominion's service territory. Dominion expects to improve customer service and business operations through advanced system control, real-time outage notification, and power quality monitoring. As part of this program, Dominion is deploying a number of smart thermostats for a residential critical peak pricing pilot during the summer of 2008. Dominion will measure customer responsiveness to changing energy prices and the impact on energy demand during peak usage periods.

These developments in technology allowing real time signaling and automated response will improve DR capabilities. However, existing technology exists for successful DR implementation and it is important to point out that there are no technology obstacles to effective DR.

D.6. Assessment of DR Potential in Arkansas

This section examines and quantifies DR potential in Arkansas. The first section outlines the general DR program categories, while the following sections outline the DR potential in the residential and commercial /industrial sectors, respectively. Then issues surrounding rate pricing are discussed, even though benefits from this form of DR are not quantified in this analysis. A summary of DR potential in Arkansas follows, and then the section concludes with a discussion of DR potential results obtained in other studies.

D.6.1. Demand Response Program Categories

For the purposes of assessing DR alternatives, the following programs could be employed in Arkansas to achieve the DR potential we outlined in this report:

Resource Category	Characteristics
Direct Load Control (DLC)	Direct load control (DLC) programs have typically been mass-market programs directed at residential and small commercial (<100 kW peak demand) air conditioning and other appliances. However, an emerging trend is to target commercial buildings with what has become known as Automated Demand Response or Auto-DR. Increased use and functionality of energy management systems at commercial sites and an increased interest by commercial customers in participating in these programs is driving growth in automated commercial curtailment in response to a utility signal. The common factor in these programs is that they are actuated directly by the utility and require the installation of control and communications infrastructure to facilitate the control process.
Callable Customer Load Response	With this type of program, utilities offer customers incentives to reduce their electric demand for specified periods of time when notified by the utility. These programs include curtailable and interruptible rate programs and demand

	bidding/buyback programs. Curtailable and interruptible rate programs can be used as "emergency demand response" if the advanced notice requirements are short enough. All customer load response programs require communications protocols to notify customers and appropriate metering to assess customer response.
Scheduled Load Control	This is a class of programs where customers schedule load reductions at pre-determined times and in pre-determined amounts. A variant on this theme is thermal energy storage which employs fixed asset technology to reduce air conditioning loads consistently during peak afternoon load periods.
Time-differentiated Rates	Pricing programs can employ rates that vary over time to encourage customers to reduce their demand for electricity in response to economic signals—in some cases these load reductions can be automated when a price trigger is exceeded. An example is a critical peak price which is "called" by the utility or system operator. In response to this critical price, residential customers can have AC cycling or temperature setbacks automatically deployed. Similar automated responses can be deployed by commercial customers. These rate programs are not analyzed for this assessment, but are further discussed in Section 3.5.

D.6.2. DR for Residential Customers

Air conditioner and other appliance direct load control (DLC) is the most common form of non-price-based DR program in terms of the number of utilities using it and the number of customers enrolled. According to FERC's 2006 assessment of DR and advanced metering, there are 234 utilities (including municipalities, cooperatives, and related entities) with DLC programs across the United States. Approximately 4.8 million customers are participating in DLC programs across the country (FERC 2006).

The prominent and growing role of air conditioning in creating system peaks makes it a high-profile candidate for DR efforts. The advances in DR technology that make AC load management economically viable make AC load control a high-priority program—one that has been proven reliable and effective at many utilities. Pool pumps are also a relatively easy and non-disruptive load that can be controlled for DR purposes.

Residential Control Strategies

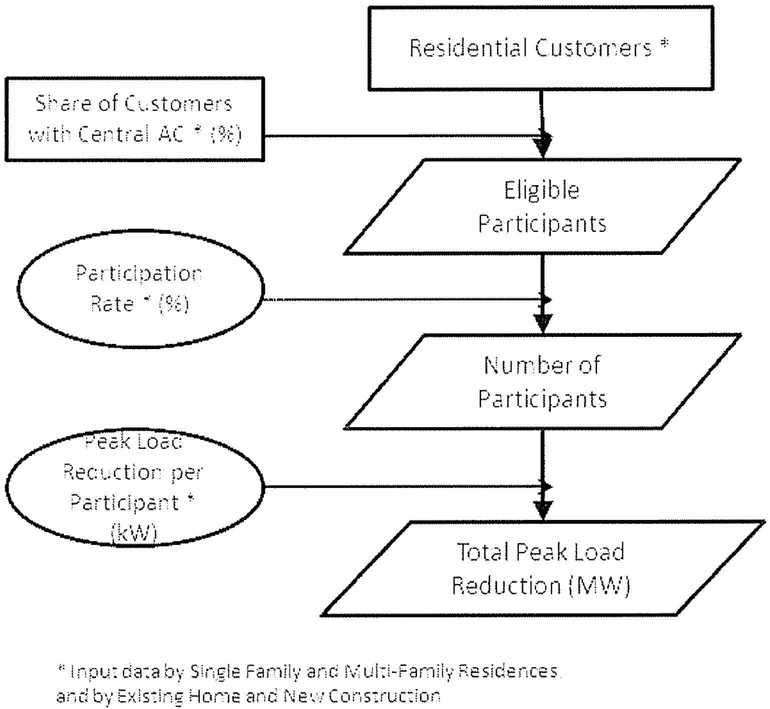
There are two basic types of control strategies: AC cycling and temperature offset. AC cycling limits ACs being on to a certain number of minutes than they otherwise would have been on. Some techniques limit ACs to being on for 50% of the minutes they would otherwise have been on. A temperature offset increases the thermostat setting for a certain period of time, for a certain number of degrees higher than it would have otherwise been set. This essentially causes the AC compressor to cycle as the temperature set-back reduces the AC demand. Sequential thermostat setbacks, i.e., one degree in a hour one, two degrees in hour two, three degrees in hour three, and four degrees in hour four can mimic an AC cycling strategy.

Cycling strategies have evolved where an optimal impact on peak kW demand may be obtained by varying the cycling time across the hours of an event. For example, there may be one hour of pre-cooling followed by 33% cycling in the first hour, 50% cycling in the second hour, 66% cycling in the third hour and dropping back to 33% in the fourth hour. Strategies like this have been deployed in pilot programs at Progress Energy Carolinas (PEC) and in PSE&G's MyPower pilot program. This type of strategy requires that forecasters accurately predict the hour(s) in which the peak system demand will occur.

Assessment of DR Potential in Residential Homes in Arkansas

For Arkansas, estimates for possible load reductions for residential housing units were obtained by applying the methodology displayed in Figure D-4.

Figure D-4. Residential Peak Load Reduction



The figure shows how load reductions and participations rates are applied to housing data. Items listed in rectangular shapes are factual inputs; items in circular shapes are assumptions; and items in parallelogram shapes are results. The analysis conducted for this study was based on demand response for summer loads, especially air conditioning, since Arkansas's major utilities are summer-peaking. However, it should be noted that some mountainous regions in the western portion of the state are winter peaking, and DR programs have targeted electric space and water heating loads.

Load Reductions

Recent surveys show that DLC programs are being implemented by a number of utilities. Load impacts are dependent on many variables. The control strategy used, the outdoor temperature, the time of day, the customer segment, ease of and ability to override control, reliability of communication signals, age and working condition of installed equipment, and local AC use patterns all have significant effects on the load impact. Even within a single program, there is variability in impacts across event days that cannot yet be fully explained. Measuring impacts typically requires expensive monitoring equipment and as a result is often done on small sample sizes.

Even with this variability, a review of reported impacts does show some general consistencies. As expected, impacts increase as the duty cycle goes up. Table D-3 shows the average reported kW impact based on 20 load control impact studies for programs based on the duty cycle used. These results support the oft-quoted rule-of-thumb that the load impact for 50% duty cycling is 1 kW per customer, which is the impact used in this analysis. However, many homes will experience an impact greater than I kW, especially newer homes.

Table D-3. Average Load Impacts by Cycling Strategy for AC DLC Programs

Cycling Strategy	Average Load Impact KW/Customer
33%	0.74
45%	0.81
50%	1.04
66%	1.36

Source: Summit Blue 2007b

Customer type also makes a difference. In a few cases where single-family and multi-family impacts were measured separately, multi-family impacts were 60% of single-family, and thus a 0.6kW load reduction is applied in this analysis for multi-family units (Summit Blue 2007b).

Eligible Residential Customers

All residential customers with central air-conditioning that live in areas that can receive control signals are considered eligible for the direct load control program. This includes single family and multi-family housing units. Residential accounts without central AC are assumed to have no participation.

Entergy stated that 63% of their customers have central AC, and Swepco stated 83% (ACEEE AR Reference Case). A weighted average of these two estimates equals 66%, and thus this is the estimate applied to the State of Arkansas for the purposes of this analysis. This is believed to be a conservative estimate, as EIA data estimate that 81% of residences in the Southeast region have central AC (EIA 2008b).

Multi-family housing units often have building tenants which are not the account holders, therefore accounts are often aggregated into buildings. Some accounts have a master meter for the entire building, including tenants. Some accounts are for the "common" building loads (i.e., those loads that are part of a building account such as elevators, A/C (if applicable), lobby lighting, etc.), but individual tenants in these buildings have their own accounts. Therefore, multi-family units often have fewer units with central AC than single family. For the purposes of this analysis, it is assumed that multi-family units have 20% less units than single family.

Residential Participation Rates

Participation rates experienced in AC DLC programs vary across utilities typically from 7% of eligible customers to 40%, depending upon the effort made in maintaining and marketing the program (Summit Blue 2007a). The utilities with the low levels of participation had essentially stopped marketing the program in recent years. Utilities with programs with sustained attention to customer retention or recruitment show higher participation rates than utilities with one-time or intermittent promotion. In Maryland, BG&E's Demand Response Service program anticipates a residential participation rate of 50%, or approximately 450,000 controlled units (BGE 2007). The pilot phase of this program was conducted from June 1 through September 30, 2007, and 58% received a "smart" load control switch, and 42% had a "smart" thermostat installed (BGE 2007). One study examined 15 AC DLC programs nationwide and found an average of 24% participation for eligible customers (Summit Blue 2008b). For this analysis, 3 typical yet conservative scenarios were used: a low scenario of 15% for eligible customers; a medium scenario of 25%; and a high scenario of 35%.

Results

Table D-4 displays the input data and results. In summary, the results for residential programs reveal that a medium scenario reduction of 92 MW is possible by 2015 (with 55 MW possible by the low scenario, and 129 MW by the high). By 2020, 193 MW is achievable through the medium scenario (with 116 MW possible by the low scenario, and 271 MW by the high).

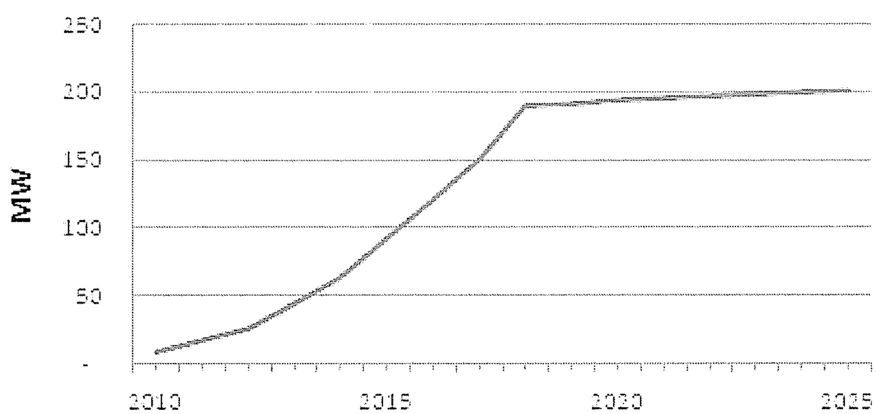
Table D-4. Potential Load Reduction from AC-DLC in Arkansas Residential Homes, in Years 2015 and 2020

INPUTS	**2015**	**2020**
Residential Peak Demand (MW)	4,410	4,657
Residential Customers (in thousands)[a]: Total	1,201	1,264
Single Family	1,025	1,073
Multi-Family	176	191
Eligible Residential Customers: Single Family[b]	66%	
Eligible Residential Customers: Multi-Family[b]	53%	
Load Reduction per AC-DLC per Single-Family Unit (kW)	1.0	
Load Reduction per AC-DLC per Multi-Family Unit (kW)	0.6	
DR Participation Rates of eligible customers:		
Low Scenario	25%	
Medium Scenario	25%	
High Scenario[c]	35%	
RESULTS	**2015**	**2020**
Residential Potential DR Load Reduction (MW):		
Low Scenario	55	116
Medium Scenario	92	193
High Scenario	129	271

Notes:
a. Residential customers reflect number of housing units, as reported from Economy.com.
b. Analysis assumes residences with central AC are eligible. Residential accounts without central AC are assumed to have no participation. Central AC percents obtained from Entergy and SWEPCO as part of ACEEE's Reference Case for AR.
c. Higher participation than applied in the High Scenario is possible through design of program features, such as "opt-out" participation where participants are included in a program unless they chose to "opt-out".

Figure D-5 shows the resulting residential load shed reductions possible for Arkansas, from year 2010, when load reductions are expected to begin, through year 2025.

Figure D-5. Potential Residential Load Shed in Arkansas (Medium Scenario)



Room Air Conditioners

Other DR residential programs could involve tapping into the potential for callable load reductions from room air conditioners. At least one prominent DR provider is exploring the possibility of having manufacturers of room AC units embedding a home-area-network communication device into new units. This would enable cycling of room air conditioners without the need to install radio frequency load switches commonly used for residential direct load control applications. Callable load reductions from room air conditioners would provide a significant boost to load control capability and these reductions would be dispatchable in less than ten minutes. Some utilities are projecting to add a large number of new room air conditioners in the next five to ten years. The additional participation of a fraction of these room AC units could provide a substantial increase to the AC DLC program.

Other Appliances

Based on the experiences of other utilities, expanding the equipment controlled to other equipment beyond AC units can produce additional kW reductions. This could include electric hot water heaters and pool pumps. However, the saturation of electric hot water heaters is lower than for air conditioning, and control of hot water heaters generally produces only about one-third the load impact of air conditioners, especially in the summer when Arkansas utilities would most likely be calling DR events.

D.7. Commercial and Industrial Potential in Arkansas

Appropriate commercial sector DR programs will vary according to customer size and the type of facility. Direct load control of space conditioner equipment is a primary DR strategy intended for small commercial customers (e.g., under 100 kW peak load), although TOU rates combined with promising new thermal energy storage technologies could prove an effective combination. Mid-to-large commercial customers and smaller industrial customers could best be targeted for a curtailable load program requiring several hours of advanced notification or, where practical, for an Auto-DR program that can deliver load reductions with no more than ten minutes of advance notice. Thermal energy storage and other scheduled load control programs may also be applicable for some larger buildings or water pumping customers. In this assessment of DR potential, the focus is on the use of direct load control and curtailable load response programs. Studies have shown that pricing programs, specifically dispatchable pricing programs such as critical peak pricing (CPP) programs can provide similar impacts. However, for the purposes of this assessment, a focus on these load response programs is believed to be able to fully represent the DR potential, even though pricing programs could be used instead of these curtailable load programs with equal, or in some cases, greater efficiency.

The following DR program descriptions apply to both commercial and industrial customers:

- Small business direct load control (air conditioning)—Small commercial customers (under 100 kW peak load) account for a majority of customer accounts but typically only about one-quarter of total commercial load. Due to the nature of small businesses, particularly their small staffs for which energy management is a relatively low priority, it is not practical to rely on active customer response to load control events. Thus, small businesses may best be viewed in the same way as residential customers for purposes of DR.

- Curtailable load program—This program would be applicable to commercial and industrial customers willing to commit to self-activated load reductions of a minimum of perhaps 50 kW in response to a notice and request from a utility. The minimum curtailment threshold is designed to improve program cost-effectiveness by ensuring that recruitment and technical assistance costs are used for customers who can deliver significant load reductions. Advanced notice requirements would likely be two hours— long enough to allow customers an opportunity to prepare but short enough to maintain the DR resource as a viable resource that can be dispatched by operations staff. Enabling technologies would vary greatly, but utilities would educate customers about alternatives and could work with equipment vendors to facilitate equipment acquisition and installation. Incentives would be paid as capacity payment (in $/kW-month) or a discount on the customers' demand charges. Utilities could also offer a voluntary version of the program to attract greater participation. Customers would not commit to load reductions, but incentives would be lower and would be paid only on the reductions achieved during curtailment events.

- Automated demand response (Auto-DR)—This program would be marketed to facilities such as high-rise office buildings and large retail businesses that have energy management and control systems (EMCS) that monitor and control HVAC systems, lighting, and other building functions. The benefits of Auto-DR over curtailable load programs include customer loads curtailments with as little as ten minutes notice and greater assurance that customers will reduce loads by at least their contracted amount. Incentives would be paid as either capacity payments or demand charge discounts, but would be greater than for curtailable load program participants due to the additional technology investment that may be required and the allowance of curtailments on relatively short notice. UTILITIES would offer extensive technical assistance in setting up Auto-DR capability and would potentially provide financial assistance as well for customers making long-term commitments.

- Scheduled load control programs (including thermal energy storage)—Scheduled load control can help reduce utility peak demand, especially through shifting of space cooling loads enabled by thermal energy storage technologies. Large-customer TES systems could be promoted along with customer commitments to reduce operation of chillers or rooftop air conditioners during specified peak hours. Customers' return on investment can be increased by encouraging migration to a TOU rate, which would offer a rate discount for many of the hours that TES systems are recharging cooling capacity. Water pumping systems are typically good candidates for scheduled load control programs and utilities can investigate opportunities in the municipal water supply and irrigation sectors. Other, less traditional, opportunities may also be available, such as the leisure/resort industry's limiting recharging of electric golf carts to off-peak hours.

- Emergency under-frequency relay (program add-on)—Under-frequency relays (UFRs) automatically shut off electrical circuits in response to the circuits exceeding pre-set voltage thresholds specified by the utility. Use of UFRs is a valuable addition to a DR portfolio because the load response is both automatic and virtually instantaneous. UFRs can best be integrated into another DR program where participants are already engaging in load curtailment activities. It is expected that some customers who might consider participating in a DR program will not be willing to allow loads to be controlled via UFR since they would not receive any advanced notice. Incentives would also need to be greater to attract participants and provide acceptable compensation. However, the benefits of UFRs warrant their consideration as part of a utility's proposed DR portfolio.

D.7.1. Commercial DR Potential in Arkansas

To estimate potential load reductions for commercial units, a straight-forward approach of applying load shed participation rates and curtailment rates directly to commercial peak demand.

First, assumptions were made on the percentage of commercial customers who are willing to participate in DR programs. One study applied commercial participation rates ranging from 11% to 48% for commercial customers (Summit Blue 2008a). Table D-5 displays participation rates for various types of commercial customers, disaggregated into two different peak demand categories (<300 kW and >300 kW).

Table D-5. Examples of Commercial Load Shed Participation Rates

	Peak Category	
Customer Segment	<300kW	>300kW
Office Buildings	11–15%	45–48%
Hospitals	13%	48%
Hotels	14%	45%
Educational Facilities	13%	43%
Retail	11%	42%
Supermarkets	12%	33%
Restaurants	11%	39%
Other Government Facilities	15%	44%
Entertainment	13%	41%

Source: Summit Blue (2008a)

Because facility-specific data was not available for Arkansas, three conservative scenarios for participation rates were applied. A medium scenario load participation rate of 20% was applied as it appears to be an average participation rate found by utilities with DR programs in place. A low scenario of 10% and a high scenario of 30% are applied.

Then, assumptions were made for curtailment rates, based on existing estimates of the fraction of load that has been shed by commercial customers enrolled in event-based DR programs callable by the utility. Table D-6 displays curtailment rates for various types of commercial customers, which range from 13% to 43%. For the purposes of this analysis, 3 conservative scenarios were applied: a low curtailment rate of 15%, a medium curtailment rate of 20%, and a high rate of 25%.

Table D-6. Examples of Commercial Curtailment Rates

Customer Segment	Average Curtailment Rate
Office Buildings	21%
Hospitals	18%
Hotels	15%
Educational Facilities	22%
Retail	18%
Supermarkets	13%
Restaurants	17%
Other Government Facilities	38%
Entertainment	43%

Source: Summit Blue 2008a

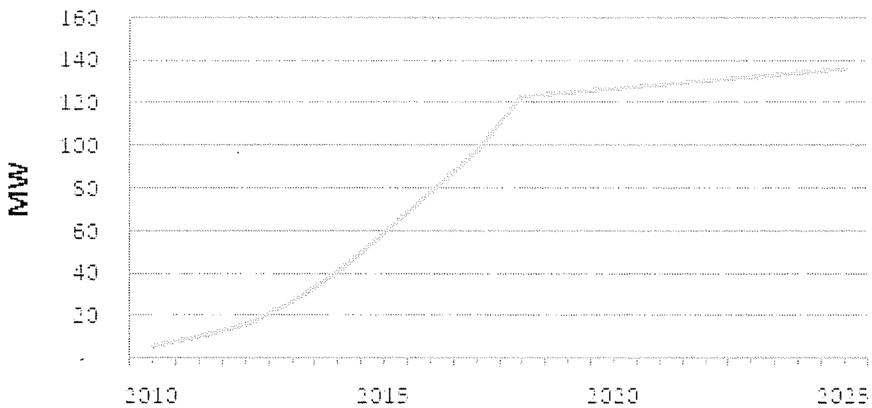
Table D-7 displays the input data and results. In summary, the commercial sector results reveal that a medium scenario cumulative reduction of 59 MW is possible by 2015 (with 22 MW possible by the low scenario, and 110 MW by the high). By 2020, 127 MW is achievable through the medium scenario (with 47 MW possible by the low scenario, and 237 MW by the high).

Table D-7. Potential Commercial Load Shed in Arkansas, in Years 2015 and 2020

INPUTS	**2015**	**2020**
Commercial Peak Demand (MW)	2,946	3,165
Load Shed Participation Rates:		
Low	10%	
Medium	20%	
High	30%	
Curtailment Rates:		
Low	15%	
Medium	20%	
High	25%	
RESULTS	**2015**	**2020**
Commercial DR load reductions (MW):		
Low	22	47
Medium	59	127
High	110	237

Figure D-6 shows the resulting commercial load shed reductions possible for Arkansas, from year 2010, when load reductions are expected to begin, through year 2025.

Figure D-6. Potential Commercial Load Shed in Arkansas (Medium Scenario)



DR programs that move towards the auto-DR concept can typically provide some load sheds that only require ten-minute notification or less. While some customer surveys have shown that most customers would prefer longer notification periods, many of these customers have not put in place the technologies to automate DR both load shed within a facility and the startup of emergency generation (ConEd 2008). The value of DR and the design of DR programs should take into account system operations. Ten-minute notice DR can be valuable in helping defer some investment in T&D. While not all customers may choose to provide ten-minute notice response, there should be an increasing number of customers that will provide this type of response in the future and programs should be designed to acquire this resource. This type of DR is often a more valuable form of DR with higher savings for the utility, and utilities are often ready to pay up to twice as much to customers for this short-notice responsiveness.

D.7.2. Industrial DR Potential

A similar analysis was conducted for the industrial sector: load shed participation rates and curtailment rates were applied to industrial peak demand. A previous study found industrial participation rates to vary from 25% for facilities <300 kW, to 50% for >300 kW (Summit Blue 2008a). For this study, the following rates were applied to participation: Low (20%); Medium (30%); and High (40%).

Previous studies have found industrial curtailment rates to vary from 17% (Quantec 2007), to 30% (CERTS 2004), to 75% (Nordham 2007), resulting in a mean of 41%. The following conservative rates were applied to curtailment for this study: Low (20%); Medium (30%); and High (40%). With these participation rates and potential load curtailments, the high load reduction potential for the overall industrial sector loads is 16% (i.e., 40% participation and 40% of that load participating).

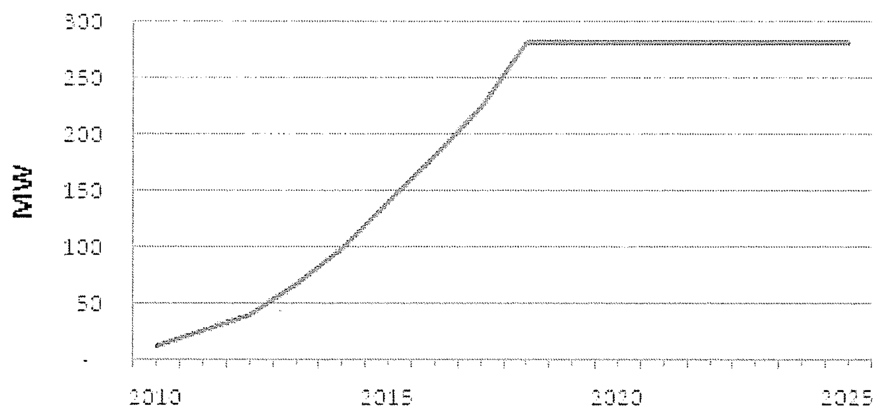
Table D-8 displays the input data and results. In summary, the industrial sector results reveal that a medium scenario cumulative reduction of 140 MW is possible by 2015 (with 62 MW possible by the low scenario, and 248 MW by the high). By 2020, 281 MW is achievable through the medium scenario (with 125 MW possible by the low scenario, and 500 MW by the high).

Table D-8. Potential Industrial Load Shed in Arkansas, in Years 2015 and 2020

INPUTS	**2015**	**2020**
Industrial Peak Demand (MW)	3,105	3,127
Load Participation Rates:		
Low	20%	
Medium	30%	
High	40%	
Curtailment Rates:		
Low	20%	
Medium	30%	
High	40%	
RESULTS	**2015**	**2020**
Industrial DR load reductions (MW):		
Low	62	125
Medium	140	281
High	248	500

Figure D-7 shows the resulting industrial load shed reductions possible for Arkansas, from year 2010, when load reductions are expected to begin, through year 2025.

Figure D-7. Potential Industrial Load Shed in Arkansas (Medium Scenario)



The largest load reductions, and often the most cost-effective, may be found in Arkansas's largest commercial and industrial customers. Data concerning these largest facilities were not available in Arkansas so estimates are not quantified separately from the industrial analysis given in the previous section.

It is a topic of concern how the economic downturn could potentially affect DR, particularly in the commercial and industrial sectors. Industry communications reveal that DR efforts have not slowed down with the economy. Many utilities are supporting DR programs, even if capacity is not a current driver. Progress Energy is continuing ahead with their DR programs and recently received approval for their C&I DR program (see Section "Assessment of Utility DR Activities").

D.7.2. Commercial and Industrial Backup Generation Potential

Emergency backup generation is a prominent component of a callable load program strategy. Some of the emergency generators not currently participating in DR programs may not be permitted for use as a DR resource and regulations may further limit the availability of emergency generation for DR. In some cases, backup generators may not be equipped with the start-up equipment to allow the generator to participate in short-term notification programs. Utilities could consider a program to assist customers with equipment specification and set-up to promote DR program participation by backup generators.

In some instances, there may be environmental restrictions on emergency generation. Emissions of emergency generation may be regulated, and the future of such regulations may add some uncertainty. However, some areas have been able to have such restrictions lifted during system emergencies.

Two approaches can increase the amount of emergency generation in DR programs: 1) facilitating customer-owned generation, and 2) utility ownership of the generation, which is used to provide additional reliability for customers willing to locate the equipment at their facilities.

Customer-owned Emergency Generation

To increase customer-owned emergency generation, utilities may assist customers with ownership of grid-synchronized emergency generation. Utilities may offer to pay for all equipment necessary for parallel interconnection with the utility grid, as well as all maintenance and fuel expenses. Once operational, the standby generators can be monitored and dispatched from a utility's control center, and they can also provide backup power during an outage. An additional benefit to the customer relative to typical backup generation is the seamless transition to and from the generator without the usual momentary power interruption.

Utility-owned Emergency Generation

A second approach to increasing the availability of emergency generation for DR is by locating generation at customer sites that can be owned by a utility. Through this type of program, the customer receives emergency generation capability during system outages in exchange for paying a monthly fee consisting of both levelized capital costs and operation and maintenance costs. Participants would likely receive capacity payments ($/kW-month) and/or energy payments ($/kWh) in exchange for granting a utility to dispatch the units for a limited number of events and total hours per year.

Backup Generation in Arkansas

Total Arkansas back-up generation capacity for 2015 is estimated at approximately 607 MW.[59] Additional analysis revealed that the commercial and industrial back-up capacity, each, is approximately half of the total capacity, at just over 300 MW.[60] Assuming a medium scenario that 40% of the total backup in Arkansas is available for load shed, then 121 MW of backup generation is available by 2015 and 251 MW is available by 2020 (see Table D-9). The low scenario estimates a 91 MW reduction by 2015 and a 189 MW reduction by 2020. The high scenario estimates a 152 MW reduction by 2015 and a 314 MW reduction by 2020.

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[59] Back-up generation capacity in Arkansas was estimated from form EIA-861 filings submitted by utilities nationwide (EIA 2010b). However, only utilities providing approximately one-quarter of total kWh report these numbers. It was assumed that the prevalence and usage of distributed generation in the remaining 75% of utilities is similar.

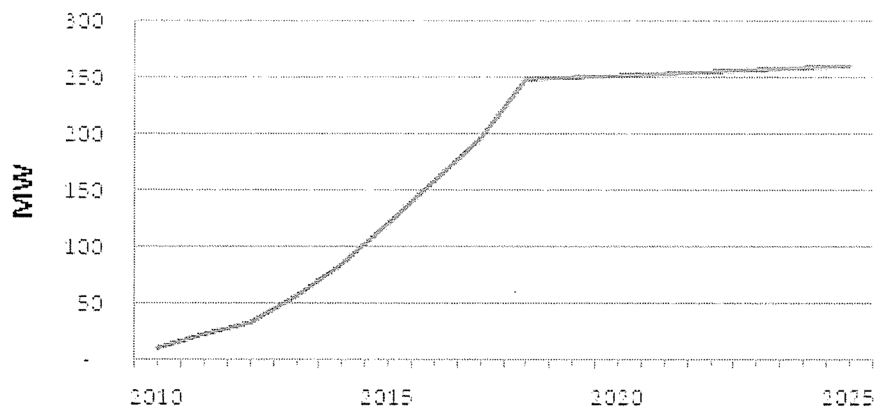
[60] The analysis first determined the back-up generator population nation-wide, and then scaled the data down to the Southeast region (CBECS resolution), accounting for proportional differences in building stock nation-wide and region-wide. The region-wide results were then scaled down to Arkansas specifically using the ratio of Arkansas population to regional population.

Table D-9. Potential Reductions from C&I Backup Generation in Arkansas, in Years 2015 and 2020

INPUTS	**2015**	**2020**
Total Backup Generation Capacity (MW)	607	629
Backup Generation Potential (%):		
Low	30%	
Medium	40%	
High	50%	
RESULTS	**2015**	**2020**
Potential Reduction from C&I Backup Generation (MW):		
Low	91	189
Medium	121	251
High	152	314

Figure D-8 shows the resulting commercial and industrial backup generation reductions possible for Arkansas, from year 2010, when load reductions are expected to begin, through year 2025.

Figure D-8. Potential Reductions from C&I Backup Generation (Medium Scenario)



D.7.3. Pricing and Rates

In this assessment of DR potential, the focus is on the use of direct load control and curtailable load response programs callable by the utility. Studies have shown that pricing programs, specifically dispatchable pricing programs such as critical peak pricing (CPP) programs can provide similar impacts; however, for the purposes of this assessment, a focus on the these load response programs is believed to be able to fully represent the DR potential, even though pricing programs could be used instead of these curtailable load programs with equal, or in some cases, greater efficiency.

New rates may be introduced as part of a DR program, and may include real-time prices, or other time-differentiated rates, for commercial and industrial customers, and a modification of any existing residential time-of-use (TOU) rates. Any new rate structures would be designed to reduce system demand during peak periods and provide an opportunity for customers to reduce electric bills through load shifting.

Critical peak pricing (CPP) is a viable option for inclusion in a DR portfolio. In FERC's 2006 survey of utilities offering DR programs (citation below), roughly 25 entities reported offering at least one CPP tariff. However, many of the tariffs were pilot programs only, and almost all of the 11,000 participants were residential customers. The apparent lack of commercial CPP programs is supported by a 2006 survey of pricing and DR programs commissioned by the U.S. EPA (below), which found only four large-customer CPP programs, all of them in California. The pilot programs in California linked the CPP rate with "automated demand response" technologies that provide most of the impact. The CPP rate itself, and the price incentive that it creates, is not the driver behind the load reductions.

As stated, rate pricing options were not analyzed in this analysis. Event-based pricing programs achieve impacts very similar to the callable load programs presented above. Pilot studies and tariff evaluations of TOU-CPP programs[61] show the load reductions for called events are similar in magnitude to air conditioning DLC programs. This is not surprising in that most TOU-CPP participants use a programmable-automated thermostat to respond to CPP events in a manner similar to a DLC strategy. One difference is that the customer response is less under the control of the program or system operator that could change cycling strategies or thermostat set points across different events or different hours within an event. Similarly, demand-bid programs are simply calls for target load sheds, i.e., those bid into the program.

In general, the direct load shed programs seem to provide greater MW of participation and more reliable reductions. However, the use of either TOU-CPP or a demand-bid program represents a point of view or policy position that price should be a centerpiece of the DR effort and should help customers see prices in the electricity markets. From a point of view of simplicity and attaining firm capacity reductions, the direct load shed programs may offer some advantages. Ultimately, the choice between these direct load shed programs and pricing programs may come down to customer preferences and decisions by policymakers on the emphasis of DR efforts.

A time-differentiated rate is another option to consider that may not be "callable." Such rates include day-ahead real-time pricing (RTP), two-part RTP tariffs, and standard TOU rates. Although they are not "callable" in that the rate is generally in effect every day, there may be synergies between time-differentiated rates and callable load programs. In general, an RTP option will result in customers learning how to reduce energy consumption on essentially a daily basis when prices tend to be high (e.g., summer season afternoons and early evenings). Customers do not tend to track exact hourly prices, but they know when prices are likely to be higher (e.g., summer season afternoons with higher prices on hot days).[62] The benefits to the customer come from reducing consumption across many summer days when prices are high, rather than a focus on reduction during system event days. In general, the reductions on system peak days are roughly the same as on any summer day when prices are reasonably high. As a result, an RTP option can provide substantial benefits by increasing overall market and system efficiency through shifting loads from high priced periods to periods with lower prices. However, these tariffs may not provide the needed load relief on system-constrained event days.[63, 64]

D.8. Summary of DR Potential Estimates in Arkansas

Table D-10 shows the resulting cumulative load shed reductions possible for Arkansas, by sector, for years 2015, 2020, and 2025. Load impacts grow rapidly through 2018 as program implementation takes hold. After 2018, the program impacts increase at the same rate as the forecasted growth in peak demand.

The high scenario DR load potential reduction is within a range of reasonable outcomes in that it has an eleven year rollout period (beginning of 2010 through the end of 2020), providing a relatively long period of time to ramp up and integrate new technologies that support DR. A value nearer to the high scenario than the medium scenario would make a good MW target for a set of DR activities.

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[61] See Public Service Electric and Gas Company, "Evaluation of the MyPower Pricing Pilot Program," prepared by Summit Blue Consulting, 2007; and the California Energy Commission, "Impact evaluation of the California Statewide Pricing Pilot—Final Report," March 16, 2005. Web reference: http://www.energy.ca.gov/demandresponse/documents/index.html#group3.

[62] See evaluations of the hourly pricing experiment offered by ComEd and the Chicago Energy Cooperative performed by Summit Blue Consulting (2003 through 2006).

[63] One way to make an RTP tariff more like an event-based DR program is to overlay a critical peak pricing (CPP) component on the RTP tariff where unusually high prices would be posted to customers with some notification period. Otherwise, it is unlikely that the high levels of reduction needed for system-event days would be attained.

[64] The complementary of event-based load shed programs with RTP tariffs is assessed in Violette, Freeman & Neil (2006). Updated results are presented in: Violette and Freeman (2007).

The high scenario results show a reduction in peak demand of 639 MW is possible by 2015 (6.1% of peak demand); 1,322 MW is possible by 2020 (12.1% of peak demand); and 1,360 MW is possible by 2025 (11.8% of peak demand).

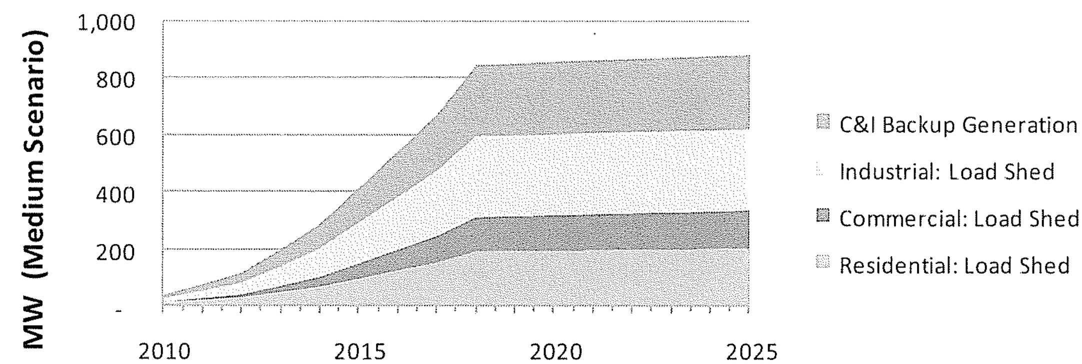
The more conservative medium scenario results show a reduction in peak demand of 412MW is possible by 2015 (3.9% of peak demand); 853MW is possible by 2020 (7.8% of peak demand); and 877MW is possible by 2025 (7.6% of peak demand).

Table D-10. Summary of Potential DR in Arkansas, by Sector, for Years 2015, 2020, and 2025

	Low Scenario			Medium Scenario			High Scenario		
	2015	2020	2025	2015	2020	2025	2015	2020	2025
Load Sheds (MW):									
Residential	55	116	120	92	193	201	129	271	281
Commercial	22	47	51	59	127	136	110	237	256
Industrial	62	125	125	140	281	280	248	500	498
C&I Backup Generation (MW)	91	189	195	121	251	260	152	314	325
Total DR Potential (MW)	230	477	491	412	853	877	639	1,322	1,360
DR Potential as % of Total Peak Demand	2.2%	4.4%	4.3%	3.9%	7.8%	7.6%	6.1%	12.1%	11.8%

Figure D-9 shows the resulting load shed reductions possible for Arkansas, by sector, from year 2010, when load reductions are expected to begin, through year 2025.

Figure D-9. Potential DR Load Reductions in Arkansas (Medium Scenario)



These estimates reflect the level of effort put forth and utilities are recommended to set targets for the high scenarios. These estimates include assumptions based on utility experience regarding growth rates, participation rates, and program design, among others, and will adjust accordingly if differing assumptions are made. The assumptions made are believed to be conservative, and reflect minimum achievable DR potential. For example, participation rates for all of the sectors are based on experience in other states, and are based primarily on customer awareness, the ability to have automated response, and the adequacy of reward. If the statewide education program now required in Arkansas promotes DR programs and adequate incentives are offered, then participation rates higher than the medium scenario are entirely realistic.

D.8.1. Comparison of Estimated DR Potential with Results from Other Studies

These estimated reductions in peak demand are within a range to be expected for a population of Arkansas's size. Estimates of DR in other states show that the estimates calculated here for Arkansas are reasonable: 15% reductions in peak demand in Florida are possible by 2023 (Elliot et al. 2007a), and 13% are possible in Texas, also by year 2023 (Elliot et al. 2007b). DR potential for a utility in New York was estimated to be 9.3% of peak demand in 2017 (Summit Blue 2008a). This finding is similar to that of a recent analysis estimating that peak load reductions from DR nationwide will be 8.2% of system peak

load in 2020 and 14% by 2030 (EPRI 2009). Estimation methods differ among the studies, but nonetheless show that the 8% to 12% reductions in Arkansas are realistic and achievable with institutional and economic commitments.
A FERC Staff Report released in the Summer of 2009 on DR potential concludes that 13% and 17% reductions are feasible in Arkansas, from the "Expanded Business as Usual" and "Achievable Potential" scenarios for 2019 (FERC 2009). The FERC Staff Report results include significant contributions from innovative pricing and rates, and are based on higher participation rates and a quicker rollout, and consequently are higher than those estimated in this report and ramp up more quickly.

As stated in the "Pricing and Rates" section of this report, the DR potential estimates focus on the use of direct load control and curtailable load response programs callable by the utility. This focus is believed to be able to fully represent the DR potential, even though pricing programs could be used instead of these curtailable load programs with equal, or in some cases, greater efficiency. Whereas the FERC estimates gain most benefits from pricing programs, this report did not examine aggressive pricing scenarios or complete restructuring of rates (covering all customers) where prices would be responsive to market effects and have considerable impact on peak demand. This report examined cases involving 10%-40% of customer load participating in DR programs. Newer visions for pricing options enabled by a smart grid infrastructure have larger numbers of customers facing real-time market pricing, resulting in greater decrease in peak demand. The FERC report's "Achievable Potential" is realized if all customers have dynamic pricing tariffs as their default tariff and 60%-75% of customers adopt this default tariff. Therefore, the estimates derived in the FERC study give further support that the results from this report are reasonable and achievable through traditional DR programs.

D.9. Recommendations

This assessment indicates that the system peak demand can be reduced by approximately 7.8% or 853 MW in 2020 in the medium case and 12.1% or 1,322 MW in the high case. The high case is considered to be within a reasonable range if aggressive action begins by the end of 2009, providing for a twelve-year rollout of the DR efforts (at the beginning of 2010 through the end of 2020).

Arkansas has a small amount of existing DR, particularly DLC programs. Enabling technologies and DLC are found to be cost-effective for all customer classes in the state (FERC 2009). However, deployment of AMI is expected to occur in the state at a slightly lower-than-average rate (FERC 2009).

Key recommendations include:

- Appropriate financial incentives for Arkansas utilities either for programs administered directly by the utilities or for outsourcing DR efforts to aggregators. The basic premise is that a utility's least-cost plan should also be its most profitable plan. Whether adequate incentives are provided for the appropriate development of DR programs in Arkansas should be examined.

- Key programs that should be offered by Arkansas energy providers which can be designed within a 12-month period include:
  - Residential and small business AC direct load control using switches or thermostats (or giving customers their choice of technology).
  - Auto-DR programs providing direct load curtailment for larger commercial and industrial customers.
  - Callable interruptible programs with manual response to an event notification for larger commercial and industrial customers where auto-DR approaches are not acceptable to the customer or technically not feasible.
  - Aggressive enrollment of back-up generators in DR programs.

- Plan for at-scale programs through the rollout period. Pilot programs can be important in determining the appropriate design of cost-effective DR programs. However, there are established DR programs and technologies. Even with the unique circumstances in Arkansas, these programs can be designed for deployment at scale. However, this approach recognizes that the first year of program deployment and possibly the second year should be designed to test key design components as part of a program shakeout. The third year of a program that should represent an efficient design and an at-scale program. DSM programs are designed to be flexible and undergo year-to-year changes due to market, customer and technology factors. This will always be the case and the benefits of discrete pilot program can limit overall program participation for a number of years resulting in "lost DR MWs." The politics of DSM and diverse positions of parties can result in a compromise in the implementation of programs leading to a two to three-year pilot program. This can delay the delivery of DR at scale resulting in higher overall costs. The over-use of pilots that do not acknowledge the ability of a program roll-out to have at-scale deliver as its goal in year three, but to also have tests of design components and decision nodes built into the first two year of program rollout can result in "death by piloting" for attainable DR MWs. Also, a decision to run a pilot program must be based on the assumption that the program will not have enough flexibility in design and on-going decision nodes during the first two years to allow for the ramp up into full scale efficient deployment in year three.

- Load reduction programs typically have less need for pilot programs as the reductions are defined by the equipment and processes outlined by the program for each participant. Time differentiated pricing is a cornerstone of efficient electric markets and the design of these programs may need more pilot testing as the customer response to pricing is voluntary and not set (as often) by program design.

- Implement programs focused on achieving firm capacity reductions as this provides the highest value demand response. This is accomplished through establishing appropriate customer expectations and by conducting program tests for each DR program in each year. These tests should be used to establish expected DR program impacts when called and to work with customers each year to ensure that they can achieve the load reductions expected at each site.

- Arkansas has some history of time-differentiated rates. Pricing should form the cornerstone of an efficient electric market. Daily TOU pricing and day-ahead hourly pricing will increase overall market efficiency by causing shifts in energy use from on-peak to off-peak hours every day of the year. However, this does not diminish the need to have dispatchable DR programs that can address those few days that represent extreme events where the highest demands occur. These events are best addressed by dispatchable DR programs.

- It is important that the DR programs be integrated with the delivery of EE programs. Many gains in delivery efficiency are possible by combining and cross-marketing EE and DR programs. These can include new building codes and standards that include not only energy efficiency construction and equipment, but also the installation of addressable and dispatchable equipment. This can include addressable thermostats in new residences and the installation of addressable energy management systems in commercial and industrial buildings that can reduce loads in select end-uses across the building/facility. In addition, energy audits of residential or commercial facilities can also include an assessment of whether that facility is a good candidate for participation in a DR program through the identification of dispatchable loads. Furthermore, building commissioning and retro-commissioning EE programs that are becoming popular in many commercial and industrial sector programs have the energy management system as a core component of program delivery. At this time, the application of auto-DR can be assessed and marketed to the customer along with the EE savings from these site-commissioning programs.

- Customer education should be included in DR efforts in Arkansas. There is some perceived lack of customer awareness of programs and incentives were programs do exist. In addition, new programs will need marketing efforts as well as technical assistance to help customers identify where load reductions can be obtained and the technologies/actions needed to achieve these load reductions. Also, high-level education on the volatility of electricity markets helps customers understand why utilities and other entities are promoting DR and the customers' role in increasing demand response to help match up with supply-side resources to achieve lower cost resource solutions when markets become tight.

Appendix E—Transportation Efficiency

E.1 Clean Car Standard

E.1.1 Efficiency Potential Methodology

The Clean Car Standard adopted by California and 15 other states to date requires that the average new vehicle's greenhouse gas emissions (GHG) be below a certain gram-per-mile level, which declines each model year. Vehicles' GHG emissions can be reduced through changes to the air conditioning system and use of reduced-carbon fuels; but the primary means of lowering GHG emissions in the near- to medium-term will be to increase vehicle fuel efficiency. The Clean Car Standard for 2016 is roughly equivalent to a fuel economy standard of 35.5 miles per gallon, although manufacturers can reduce their vehicle efficiency obligations to some extent by reducing vehicles' air conditioning-related GHG emissions. The level of the standard was set on the basis of an examination of existing and emerging vehicle efficiency technologies that could be applied cost-effectively to new vehicles. The assessment assumed that the distribution of vehicles among size classes will not be affected by implementation of the standards (CARB 2008). In 2010, the federal government (EPA and NHTSA) adopted standards that will match California's in stringency by 2016.

In an October 2010 Notice of Intent to set vehicle standards for the period 2017-2025, EPA and NHTSA explored standards ranging from 43.4 mpg to 56.2 mpg. California is working to set post-2017 standards as well, and retains the right to adopt standards more stringent than those set by the federal government. Other states would then choose whether to adopt the California standards or accept the federal standards.

The policy considered for this analysis is Arkansas' adoption of a standard that reaches 60 mpg by 2025, going above and beyond the upper end of federal government's range. To calculate fuel savings from this policy, we assumed that EPA and NHTSA will adopt a standard of 49.8 mpg for 2025, the midpoint of the range set out in their Notice of Intent. This federal standard was taken as the reference case for our analysis.

Improvements in the fuel economy of new vehicles take many years to spread throughout the vehicle stock. For a given efficiency gain among new vehicles, ACEEE uses a "stock model" to calculate the resultant increase in average efficiency of all vehicles over time. In the case of the Clean Car Standard, this increase in stock efficiency leads to the reductions in fuel consumption relative to fuel consumption in the reference case.

E.1.2 Cost Methodology

The California Air Resources Board estimated the increase in the purchase cost of the vehicles when the first round of standards came into effect for the years 2009-2016. By 2015, the purchase cost of the average vehicle is expected to increase by $822. For the post-2016 period, we assume that the average cost increase per vehicle reaches $3,000 in 2025. Even this high incremental cost would be recouped in fuel savings in the first five years of ownership. Using these cost estimates and assuming that vehicle sales in Arkansas grow according to data obtained from Economy.com projections, we estimate that investments for the clean car standard will total $1.2 billion in 2007 dollars in both the medium case and high case.

To calculate program costs for the clean car standard, we assume that the state of Arkansas will require one administrator for the program, three additional staff to assist in implementation and subsequent monitoring and one administrative staff member. ACEEE estimates that program costs will amount to $300,000 annually (2007 dollars).

E.2 Pay-As-You-Drive Insurance

E.2.1 Efficiency Potential Methodology

Estimates of the reduction in vehicle-miles traveled (VMT), and therefore energy use, resulting from a PAYD policy depend upon the price elasticity of travel demand, i.e., the percent change in travel resulting from each percent increase in the cost of travel. Researchers' estimates of elasticity vary considerably, and estaticities also differ according to the time elapsed between the change in cost and the response to it. We use here a value of -0.15 for the long-term elasticity of driving with respect to travel cost; that is, over 10-15 years, we assume there is a 1.5 percent reduction in driving for a 10 percent increase in the cost of travel (Greene & Lieby 2006; Litman 2007; Bordoff & Noel 2008). The average per-mile cost of gasoline between 2010 and 2025 is projected to be 11 cents per mile. The cost of the average insurance policy in Arkansas in 2007 was $660, which we keep constant through 2025. This means that the average insurance cost per mile over the same time period is 5 cents per mile.

If 80 percent of the cost of the insurance premium were charged on a per-mile basis, the variable cost per mile of driving would then be increased by 4 cents per mile, or by an average of about 36 percent between 2010 and 2025. An elasticity of -0.15 implies a corresponding reduction in driving of 5.3 percent. Thus 100 percent adoption of PAYD insurance would be expected to reduce car and light truck energy use in Arkansas by 5.3 percent over 10-15 years in the high case. In the medium case, PAYD insurance would be required in high-growth counties only, lowering statewide VMT and fuel use reductions to 2.4 percent.

The pay-as-you-drive insurance program we analyzed for Arkansas begins with a three-year pilot program subsidized by the State. The State would offer insurance companies a $200 incentive per PAYD policy, with goals of 2,000 policies in 2010, 10,000 policies in 2011, and 20,000 policies in 2012. A mandatory program would then be phased in over the next ten years. Miles driven would be tracked using the odometer or a GPS, for instance. Numbers would periodically be reported back to insurance companies to verify mileage.

An alternative approach to reduce VMT through monetary incentives would be increasing the state gas tax. Arkansas' gas tax stands at 21.5 cents per gallon (FHWA 2008). As noted above, PAYD insurance would in effect increase the variable cost of driving by 4 cents per mile. Achieving the same cost-per-mile increase today by raising the gas tax would require an increase of $0.82 per gallon in the gas tax, something the Arkansas legislature may be reluctant to propose.[65] Also, a gas tax increase, unlike PAYD insurance, would increase the tax burden in aggregate unless offset by reductions in other taxes such as income tax.

E.2.2 Cost Methodology

Direct costs to the state would be $200 per PAYD policy in the first three years. This means costs of $400,000 in 2010, $2 million in 2011, and $4 million in 2012 assuming the goals are met (in 2007 dollars).

To estimate the total cost to the insurance companies that are required to undertake PAYD policies, we assume that each PAYD policy costs the insurance company $40 in additional expenses during the pilot period. This may include the reorganization of services to cater to such policies or even the installation of tracking equipment in each insured vehicle. Once the pilot period ends, this cost of implementation falls to $10 per policy as we assume that insurance companies have had sufficient adjustment time to reduce their overall costs. Costs to insurance companies will amount to $124 million between 2010 and 2025.

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[65] A gas tax increase of $0.82 per gallon would in fact reduce fuel consumption by more than a PAYD policy in the long-term because it would affect not only the amount people drive but also their choice of vehicle. We are proposing other mechanisms to increase vehicle efficiency, however.

E.3 Compact, Transit-Oriented Development

E.3.1 Efficiency Potential Methodology

The approach to reducing vehicle miles traveled through compact development and expanded transit focuses on the 6 high-growth counties in Arkansas. These include the counties surrounding Little Rock and Benton and Washington counties in Northwest Arkansas.

According to a recent National Academy of Sciences study, the amount that people drive is related to the population density of the area in which they live: a doubling of density alone would typically mean 5 to 12 percent fewer vehicle miles traveled per person (TRB 2009). This reduction in VMT can be far larger, up to 25 percent, with supporting policies such as improved transit and improved connectivity between streets.

For this policy, we assumed that an increasing percentage of new residents of these high-growth areas would live within a half-mile of an existing or planned light rail, commuter rail, or bus rapid transit stop. Movement into these areas close transit ramps up incrementally to 50% between 2012 and 2020, and remains steady at this level thereafter.

Beyond the savings from avoided fuel costs, compact development has the ancillary benefit of reducing infrastructure costs (water mains, roads, utilities, etc). In Sacramento's Blueprint Plan, the Sacramento Area Council of Governments (SACOG) estimated that compact development would cut infrastructure costs by $18,000 for every housing unit located within a ½ mile of new transit nodes (SACOG 2005). To reflect these savings, we included this benefit in our macroeconomic analysis by multiplying the per unit benefit by the number of new homes located within that ½ mile. According to SACOG, this benefit also applies to commercial space, where the $18,000 benefit accrues to every 2,500 square feet or office or commercial space, but we did not include the benefits stemming from the commercial sector, so our savings estimate is conservative.

We calculated the resultant increase in density in the areas within a half-mile of transit stops and used the TRB results to project a reduction in VMT for residents of these higher density areas relative to VMT per capita elsewhere in the county. The number of transit stops was taken from planning studies conducted by Metroplan (Metroplan 2009) and the City of Fayetteville, whose light rail proposal was taken from a study conducted by Beta-Rubicon (City of Fayetteville 2009). Specifically, given the proximity to transit, we assumed that each doubling of density would reduce VMT, and therefore fuel use, by 15 percent in the medium case and by 25 percent in the high case. VMT for residents outside these transit-served areas would remain unchanged.

Information on transit expansion initiatives was obtained for the two major metro areas: Little Rock and the Fayetteville/Springdale/Rogers/Bentonville metropolitan area.

E.3.2 Cost Methodology

Transit infrastructure investment costs for this policy were estimated based on cost assumptions reported in Metroplan's Metro 2030.2 report for three proposed light rail lines from the surrounding suburbs into Little Rock. Based on the costs reported and an estimated total length for the three lines of about 50 miles, we estimated total annual capital and operating costs of $36 million per mile, with maintenance and operation costs assumed to be 7.4% of the total investment (see Table 17-3 of Metro 2030.2). We used this per-mile cost estimate for the Northwest Arkansas region as well, assuming a total of 60 miles for the proposed system. Since these costs represent the total capital cost of the project, we assumed that the projects would take 5 years to complete and divided the total cost per mile by the total project time to get the cost per mile per year. Therefore, after 2016, the only costs associated with the light rail systems are maintenance and operation costs. Total costs equal $3.4 billion between 2012 and 2025 under both the medium and high case scenarios.

Focusing new development in the vicinity of transit stops has many implications for investment, which we do not explore here. The cost of non-transit infrastructure, including roads and water/wastewater systems, would be generally lower in this compact development scenario than in the Reference Case. We do, however, consider the incentives that will likely be necessary in order to support the development of transit-oriented communities. We assume that each new additional housing unit built in these areas will be given a subsidy of $5000, bringing total incentive costs under both the medium and high case scenarios to $84.5 million in 2015 and almost $300 million in 2025.

To project the administrative costs associated with this transit-oriented development policy, we assumed that each high-growth county transit agency would require one administrator, two additional research staff and one support staff member to administer such a program at respective costs of $90,000, $55,000 and $30,000. In addition to personnel expenses, the state will likely undertake a large-scale educational campaign to support their transit investments. We estimate that this campaign will cost $2.4 million. Annual program costs will be $3.8 million (2007 dollars).

E.4 Truck Stop Electrification

E.4.1 Efficiency Potential Methodolgy

We assume that the number of truck stops in the state grows annually at the same rate as heavy-duty VMT. Based on 2010 survey data supplied by the Arkansas State Highway and Transportation Department (AHTD 2010b), there are currently 5718 spaces at truck stops and rest areas statewide. We expect this number to grow in line with heavy-duty VMT, for a total of approximately 8500 spaces by 2025.

An idling heavy truck consumes about one gallon of fuel per hour (Stodolsky et al. 2000; Idleair 2010). Assuming each truck stop space is used for eleven hours per day by two separate trucks, 306 days of the year (Idleair 2010), annual fuel savings in Arkansas would be 554 thousand barrels in 2015 and 680 thousand barrels by 2025 in both the medium case and the high case scenarios. The power requirement of the truck while using the TSE system is approximately 2.1 kW (Lutsey 2003), and we assume a heat rate of 10,764 Btu/kWh to produce the electricity that powers the TSE (EIA 2010). Assuming each space is used for 3366 hours annually, the total net energy savings from truck stop electrification amount to approximately 3.3 trillion Btus annually by 2025.

E.4.2 Cost Methodology

The cost of truck stop electrification is about $15,000 per space for an off-board system (EPRI 2004). We assume all spaces are converted by 2025. Investment costs over the period 2010 and 2025 total $127 million under both the medium and high case scenarios, with the bulk of that ($90 million) taking place in the first year, with smaller costs thereafter covering incremental growth in the number of spaces. Annual program administration costs are approximately $300,000.

E.5 Heavy-Duty Efficiency Incentive Package

E.5.1 Efficiency Potential Methodology

Trucks that can use auxiliary power units (APUs) to eliminate overnight idling are medium- and long-distance trucks of Classes 7 and 8 (i.e., those having gross vehicle weight rating of 26,000 lbs. or more). Here we define "medium-distance" as those having a primary range of 201-500 miles and "long-distance" as those having a range of operation over 500 miles; these trucks are frequently away from their home bases at night. To determine the number of such trucks registered in Arkansas, we used the 2002 Vehicle Inventory and Use Survey data (US Census Bureau 2004). Of the state's 1000 such trucks (in 2002), we estimate that 40 percent already have anti-idling technology, leaving 600 trucks eligible for auxiliary power units under the high case mandate (in the medium case incentive we assume that only 2/3 of eligible trucks will adopt the technology). Fuel consumption at idle is roughly one gallon per hour, and a typical truck idles for 1830 hours each year. A diesel-fueled APU uses on the order of 0.18 gallons per hour, resulting in net savings for each truck of 1,500 gallons per year (Stodolsky et al. 2000).

The SmartWay upgrade kit also includes energy-efficient tires and trailer side skirts. As above, we assume that trucks typically driving 200 or more miles per day travel at high speeds, and so a subset of Arkansas' stock of 1000 trucks would also be eligible for these upgrades. In the medium case, we assume that half of these trucks (500) will purchase this type of equipment, and in the high case, we assume that 75% (750) will. Efficient tires and side skirts reduce fuel consumption by 4 percent each (EPA 2009); we utilize a multiplicative approach to calculate their combined impact on fuel consumption.

The EPA has demonstrated that a low-interest loan program would allow truckers purchasing equipment in the SmartWay package to realize fuel cost savings that exceed their monthly loan payments. We assume that usage of the loan program ramps up over five years, reaching all trucks eligible for the various types of equipment by 2015 under each scenario.

Fuel savings from the program of SmartWay upgrades total about 0.2 percent of all diesel consumption in the medium case scenario. Under the high case scenario, in which we assume the SmartWay program is mandatory, this percentage increases to approximately 0.3 percent.

E.5.2 Cost Methodology

Administrative cost values are based on the assumption that the program will be centrally administered and that Arkansas requires one administrator, three research staff and one administrative staffer with respective salaries of $90,000, $55,000 and $30,000. Annual administrative costs amount to $285,000 in 2007 dollars.

Regarding investment costs, the typical SmartWay upgrade kit costs $16,500. We estimate that the total investments between 2011 and 2025 in the medium case amount to $9.6 million. In the high case, total investments are approximately $14.3 million, and program costs are the same as in the medium case.

E.6 Intermodal Freight Investment

E.6.1 Efficiency Potential Methodology

Shifting freight from truck to another mode decreases fuel use from trucks but increases fuel use by the other mode(s). However, because rail and marine modes consume 38 percent and 27 percent, respectively, of the fuel per ton-mile consumed by trucks (MARAD 2007), overall fuel consumption is lower for the same number of ton-miles. We assume, as is the case nationally,[66] that long-haul trucks in Arkansas are responsible for 60 percent of state diesel consumption. We also assume that the infrastructure investments leading to increased rail and marine shares of freight movement will be phased in over fifteen years, starting in 2011.

Diverting 10 percent of long-haul truck freight to rail and 3 percent to marine under the high case scenario would reduce diesel consumption by 5.1 percent by 2025. Under the medium case scenario, a diversion of 7 percent truck-to-rail and 2 percent truck-to-barge yields diesel savings of 3.5 percent by 2025.

E.6.2 Cost Methodology

As was noted in the main text, we do not attempt to fully specify the rail and marine projects required to support the percentage diversions modeled under this policy. As a rough estimate of the cost of infrastructure investment needed to realize the assumed mode shift, we calculate a cost per barrel saved

[66] Calculated from the 2002 Vehicle Inventory and Use Survey data (US Census Bureau 2004).

from a group of investment estimates for similar projects in the state (AHTD 2005; AHTD 2002; Norfolk Southern 2010). Together, these projects are projected to cost approximately $300 million, and we estimate average annual savings of 526 thousand barrels of diesel from mode shifting. Therefore, investment costs for the intermodal policy described in this report would total $450 million between 2010 and 2025 in the medium case scenario and $650 million in the high case scenario.

Administrative costs were calculated based on the assumption that the state-wide program would require, like other large infrastructure projects, a number of new staff: twelve program administrators, twelve research staff and twelve support staff at the respective costs of $90,000, $55,000 and $33,000. Annual administrative and program costs are estimated to be $5.6 million.

E.7 Reduced Speed Limits

E.7.1 Efficiency Potential Methodology

In many states, recommended practice is to set speed limits at the 85th percentile of driving that occurs on the roadway. In reality, speed limits are set lower than this for most roads; on average, over half of all traffic travels over the speed limit. Virtually all vehicles are within 10 miles of the limit, however (TRB 2003).

To estimate energy savings from additional enforcement, we assume that: 1) 50% of vehicles on highways are exceeding speed limits; 2) that they are exceeding the limit by 5 miles per hour on average; and 3) that their fuel economy is consequently 8% lower than it would be if traveling at the speed limit. In Arkansas, 60% of all driving is on highways (AHTD 2008). This leads to an estimate of energy savings of up to 2.4% from improved enforcement of speed limits in both the Medium and High Case.

E.7.2 Cost Methodology

The Washington State Energy Office estimates that a speed limit enforcement program costs an average of $140 per ton of carbon dioxide controlled to implement (EPA 2010). We applied this cost value to the potential CO2 reduction estimates from the analysis to arrive at average annual costs of $35 million for the speed limit program described here.

We assume that there are no administrative costs associated with this policy.

E.8 Efficient State Vehicle Fleet

E.8.1. Efficiency Potential Methodology

States often implement procurement policies that require, to some degree, the purchase of fuel-efficient vehicles.

Using state fleet data obtained through the Arkansas Department of Finance and Administration, we estimated the potential gasoline savings that would arise from the implementation of a best-in-class procurement policy for cars and light trucks, the latter of which consists of vans (passenger, utility), pickup trucks, and sports utility vehicles (SUVs). To estimate savings, we first determined a baseline average fuel economy for cars and light trucks. Given the limited number of car models in Arkansas' fleet, we were able to use the fuel economies for specific car models, and weight those fuel economies by the volume purchased to obtain a baseline average for the entire fleet of cars. For light duty trucks, the estimated baseline average fuel economy for the entire light duty truck fleet is based on national average fuel economies for the three subclasses (vans, pickups, and SUVs). Our fuel economy estimates for the three truck subclasses thus are not model-specific, but they are weighted by subclass shares that are specific to Arkansas.

Estimates of the fuel economies of the best-in-class for both cars and light duty trucks were taken from the EPA's *Light-Duty Automotive Technology, Carbon Dioxide Emissions, and Fuel Economy Trends* report for 2010 (EPA 2010). Savings estimates were calculated by determining the percent increase in fuel efficiency between the baseline average fuel economies for cars and light duty trucks and the respective fuel economies for the best-in-class models. We assume that cars and light duty trucks travel an average of 15,000 miles per year, respectively, and that the state purchases 218 cars and 373 trucks annually to replace those that have been decommissioned:

*Annual Gallons Saved = assumed annual mileage / average fleet fuel economy * % reduction in fuel consumption * total efficient vehicles purchased*

Our medium case scenario is based on the replacement of each fleet vehicle, upon retirement, with the most efficient conventional (i.e., not hybrid) vehicle that is functionally similar. Our high case has the additional assumptions of a 10% hybrid purchase requirement as well as a shifting of 33% of LD truck purchases to cars.

To calculate the economic savings generated by this policy, we assumed gasoline costs the state $2.67 per gallon, which does not include the state gasoline tax of 21.5 cents per gallon, and multiplied the fuel cost by the gasoline savings.

E.8.2. Cost Methodology

There is no consistent pattern in the cost of best-in-class vehicles relative to the cost of the average vehicle in the class, and we assume that, on average, the purchase of best-in-class vehicles has no impact on the purchase cost. We also assume resale value and maintenance cost for these vehicles are the same as for the average vehicle.

Due to time and data constraints, we did not attempt to estimate the associated program costs from this policy recommendation.

Appendix F—Combined Heat and Power

F.1. Technical Potential for CHP

This section provides an estimate of the technical market potential for combined heat and power (CHP) in the industrial, commercial/institutional, and multi-family residential market sectors. The analysis focused on the potential market for natural gas fueled CHP in Arkansas. Natural gas is by far the predominant fuel used for CHP in the U.S, representing 72 percent of the 84,300 MW of installed CHP capacity in the country. Natural gas is the fuel of choice for most CHP applications because of its competitive price, ease of use, reliability of supply, relatively low criteria pollutant emissions, and increasingly, its low carbon content in comparison to coal and oil. If properly designed and operated, natural gas CHP can provide significant benefits in terms of energy efficiency and reduced CO2 emissions.

Two different types of CHP markets were included in the evaluation of technical potential, markets that employ the CHP thermal energy for boiler loads only and markets that employ the thermal energy for both boiler loads and air conditioning. Both of these markets were evaluated for high load factor (80% and above) and low load factor (51%) applications resulting in four distinct market segments that are analyzed.

F.1.1. Traditional CHP

Traditional CHP electrical output is produced to meet all or a portion of the base load for a facility and the thermal energy is used to provide steam or hot water. Depending on the type of facility, the appropriate sizing could be either electric or thermal limited. Industrial facilities often have "excess" thermal load compared to their on-site electric load. Commercial facilities almost always have excess electric load compared to their thermal load. Two sub-categories were considered:

High load factor applications: This market provides for continuous or nearly continuous operation. It includes all industrial applications and round-the-clock commercial/institutional operations such colleges, hospitals, hotels, and prisons.

Low load factor applications: Some commercial and institutional markets provide an opportunity for coincident electric/thermal loads for a period of 3,500 to 5,000 hours per year. This sector includes applications such as car washes and health clubs.

F.1.2. Combined Cooling Heating and Power

All or a portion of the thermal output of a CHP system can be converted to air conditioning or refrigeration with the addition of a thermally activated cooling system. This type of system can potentially open up the benefits of CHP to facilities that do not have the year-round thermal load to support a traditional CHP system. A typical system would provide the annual hot water load, a portion of the space heating load in the winter months and a portion of the cooling load in during the summer months. Two sub-categories were considered:

Low load factor applications: These represent markets that otherwise could not support CHP due to a lack of thermal load. This market includes applications such as office buildings, retail, education, and government buildings

High load factor applications: These markets represent round-the-clock commercial/institutional facilities with cooling and heating loads. This market includes hotels, hospitals, nursing homes, and data centers.

The estimation of technical market potential consists of the following elements:

- Identification of applications where CHP provides a reasonable fit to the electric and thermal needs of the user. Target applications were identified based on reviewing the electric and thermal energy consumption data for various building types and industrial facilities.

- Quantification of the number and size distribution of target applications. Several data sources were used to identify the number of applications by sector that meet the thermal and electric load requirements for CHP.

- Estimation of CHP potential in terms of megawatt (MW) capacity. Total CHP potential is then derived for each target application based on the number of target facilities in each size category and sizing criteria appropriate for each sector.

- Subtraction of existing CHP from the identified sites to determine the remaining technical market potential.

The technical market potential defines the sites that have the physical electric and thermal loads that could support CHP with the defined loads in the four market segments. Technical potential does not consider screening for economic rate of return, or other factors such as ability to retrofit, owner interest in applying CHP, capital availability, natural gas availability, and variation of energy consumption within customer application/size class. The technical potential as outlined is useful in understanding the potential size and size distribution of the target CHP markets in the state. Identifying technical market potential is a preliminary step in the assessment of market penetration.

The basic approach to developing the technical potential is described below:

- Identify existing CHP in the state. The analysis of CHP potential starts with the identification of existing CHP. In Arkansas, there are 59 operating CHP plants totaling 497.3 MW of capacity in 16 sites. Of this existing CHP capacity, 69% of the sites and 96% of the capacity are in the industrial sector. Biomass and waste fuels, predominantly in the forest products industries, make up 93% of the total CHP capacity. Most of the remaining 7% of capacity is natural gas fired. The portion of this existing CHP capacity that is used to meet on-site loads is deducted from any identified technical potential. A summary of the existing CHP capacity by industry is shown in Table F-1.

- Identify applications where CHP provides a reasonable fit to the electric and thermal needs of the user. Target applications were identified based on reviewing the electric and thermal energy (heating and cooling) consumption data for various building types and industrial facilities. Data sources include the DOE EIA Commercial Buildings Energy Consumption Survey (CBECS), the DOE Manufacturing Energy Consumption Survey (MECS) and various market summaries developed by DOE, Gas Technology Institute (GRI), and the American Gas Association. Existing CHP installations in the commercial/institutional and industrial sectors were also reviewed to understand the required profile for CHP applications and to identify target applications.

- Quantify the number and size distribution of target applications. Once applications that could technically support CHP were identified, the Dun & Bradstreet Selectory Database and the Major Industrial Plant Database (MIPD) from IHS were utilized to identify potential CHP sites by SIC code or application, and location. The Selectory Database is based on the Dun and Bradstreet financial listings and includes information on economic activity (8 digit SIC), location (metropolitan area, county, electric utility service area, state) and size (number of employees) for commercial, institutional and industrial facilities. The data on number of employees is used to calculate the electric and thermal loads of the facility based on detailed estimates of energy use per employee. The MIPD has detailed energy and process data for 16,000 of the largest energy consuming industrial plants in the United States. The Selectory Database and MIPD were used to identify the number of facilities in target CHP applications and to group them into size categories based on average electric demand in kilowatt-hours.

- Estimate CHP potential in terms of MW capacity. Total CHP potential was then derived for each target application based on the number of target facilities in each size category. It was assumed that the CHP system would be sized to meet the average site electric demand for the target applications unless thermal loads (heating and cooling) limited electric capacity. Tables F-2 through F-4 present the specific target market sectors, the number of potential sites and the potential MW contribution from CHP. There are two distinct applications and two levels of annual load making for four market segments in all. In traditional CHP, the thermal energy is recovered and used for heating, process steam, or hot water. In cooling CHP, the system provides both heating and cooling needs for the facility. High load factor applications operate at 80% load factor and above; low load factor applications operate at an assumed average of 4500 hours per year (51%) load factor.

- Estimate the growth of new facilities in the target market sectors. The technical potential included economic projections for growth through 2025 by target market sectors in Arkansas. The growth factors used in the analysis for growth between the present and 2025 by individual sector are shown in Table F-5. These growth projections provided by ACEEE were used in this analysis as an estimate of the growth in new facilities. In cases where an economic sector is declining, it was assumed that no new facilities would be added to the technical potential for CHP. Based on these growth rates the total technical market potential is summarized in Table F-6.

Table F-1. Arkansas Existing CHP Facilities

SIC	Application	Sites	Capacity (MW)
20	Food Processing	3	18.7
24	Wood Products	3	32.0
26	Paper	4	423.5
29	Refining	1	3.5
4952	Wastewater Treatment	2	2.2
4953	Solid Waste	1	4.8
8060	Healthcare	1	8.5
8220	College/University	1	4.1
	Total	**16**	**497.3**

Table F-2. Arkansas Technical Market Potential for CHP in Existing Facilities—Industrial Sector

SIC	Application	50-500 kW Sites	50-500 kW (MW)	500-1 MW Sites	500-1 MW (MW)	1-5 MW Sites	1-5 MW (MW)	5-20 MW Sites	5-20 MW (MW)	>20 MW Sites	>20 MW (MW)	Total Sites	Total MW
20	Food	127	22.8	30	22.2	40	97.5	9	74.2	0	0.0	206	216.8
22	Textiles	15	1.8	1	0.7	0	0.0	0	0.0	0	0.0	16	2.5
24	Lumber and Wood	252	31.0	12	8.9	15	31.9	1	6.1	0	0.0	280	77.9
25	Furniture	4	0.5	1	0.8	0	0.0	0	0.0	0	0.0	5	1.4
26	Paper	49	8.8	15	10.1	7	21.4	2	21.6	1	37.0	74	98.8
27	Printing	9	1.0	0	0.0	0	0.0	0	0.0	0	0.0	9	1.0
28	Chemicals	58	11.0	8	5.2	24	53.3	4	43.4	4	128.1	98	240.9
29	Petroleum Refining	23	5.8	7	4.2	2	6.6	1	7.7	1	36.6	34	60.9
30	Rubber/Misc. Plastics	51	8.7	5	3.5	2	2.6	1	14.4	0	0.0	59	29.2
32	Stone/Clay/Glass	5	0.9	1	0.7	0	0.0	0	0.0	0	0.0	6	1.5
33	Primary Metals	12	1.9	2	1.4	3	10.4	3	28.0	1	31.7	21	73.3
34	Fabricated Metals	6	0.9	0	0.0	0	0.0	0	0.0	0	0.0	6	0.9
35	Machinery/Computer Equip	2	0.1	0	0.0	0	0.0	0	0.0	0	0.0	2	0.1
37	Transportation Equip.	16	3.5	6	3.9	1	1.9	0	0.0	0	0.0	23	9.3
38	Instruments	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
39	Misc. Manufacturing	5	0.6	2	1.4	0	0.0	0	0.0	0	0.0	7	2.0
	Total	**634**	**99.2**	**90**	**63.1**	**94**	**225.7**	**21**	**195.3**	**7**	**233.4**	**846**	**816.6**

Table F-3. Arkansas Technical Market Potential for CHP in Existing Facilities—Commercial, Traditional

SICs	Application	50-500 kW Sites	50-500 kW MW	500-1 MW Sites	500-1 MW (MW)	1-5 MW Sites	1-5 MW (MW)	5-20 MW Sites	5-20 MW (MW)	>20 MW Sites	>20 MW (MW)	Total Sites	Total MW
Commercial, Multifamily(Traditional, High Load Factor)													
6513	Multifamily Buildings	28	7.0	10	7.5	2	4.0	0	0.0	0	0.0	40	18.5
4952	Water Treatment	56	6.4	2	1.1	0	0.0	0	0.0	0	0.0	58	7.5
8221	College/Univ.	38	7.1	5	3.1	3	5.2	2	19.0	0	0.0	48	34.4
9223	Prisons	14	1.6	2	1.1	0	0.0	0	0.0	0	0.0	16	2.7
	Total C/I High LF	**136**	**22.2**	**19**	**12.8**	**5**	**9.2**	**2**	**19.0**	**0**	**0.0**	**162**	**63.1**
Commercial (Traditional, Low Load Factor)													
7211	Laundries	18	2.9	0	0.0	0	0.0	0	0.0	0	0.0	18	2.9
7542	Car Washes	12	0.9	0	0.0	0	0.0	0	0.0	0	0.0	12	0.9
7991	Health Clubs	13	1.4	1	0.6	0	0.0	0	0.0	0	0.0	14	1.9
7997	Golf/Country Clubs	35	4.5	0	0.0	0	0.0	0	0.0	0	0.0	35	4.5
8412	Museums	2	0.2	0	0.0	0	0.0	0	0.0	0	0.0	2	0.2
	Total C/I Low LF	**80**	**9.8**	**1**	**0.6**	**0**	**0.0**	**0**	**0.0**	**0**	**0.0**	**81**	**10.4**
	Total C/I Traditional	**216**	**32.0**	**20**	**13.3**	**5**	**9.2**	**2**	**19.0**	**0**	**0.0**	**243**	**73.5**

Table F-4. Arkansas Technical Market Potential for CHP in Existing Facilities—Commercial, Cooling

SICs	Application	50-500 kW Sites	50-500 kW (MW)	500-1 MW Sites	500-1 MW (MW)	1-5 MW Sites	1-5 MW (MW)	5-20 MW Sites	5-20 MW (MW)	>20 MW Sites	>20 MW (MW)	Total Sites	Total MW
Commercial Cooling, High Load Factor													
4222	Refrigerated Warehouses	15	2.0	2	1.3	0	0.0	0	0.0	0	0.0	17	3.3
7011	Hotels	150	16.2	4	2.6	2	2.7	0	0.0	0	0.0	156	21.6
7374	Data Centers	5	0.8	3	2.2	3	6.1	1	12.0	0	0.0	12	21.2
8051	Nursing Homes	172	22.2	3	2.1	0	0.0	0	0.0	0	0.0	175	24.4
8062	Hospitals	67	13.4	10	7.5	14	27.7	1	12.1	0	0.0	92	60.7
	Total Cooling High LF	**409**	**54.6**	**22**	**15.9**	**19**	**36.5**	**2**	**24.1**	**0**	**0.0**	**452**	**131.1**
Commercial Cooling, Low Load Factor													
5411	Food Stores	126	13.3	0	0.0	0	0.0	0	0.0	0	0.0	126	13.3
5812	Restaurants	274	29.9	1	0.5	0	0.0	0	0.0	0	0.0	275	30.4
43	Post Offices	4	0.5	0	0.0	0	0.0	0	0.0	0	0.0	4	0.5
4581	Airports	6	0.6	0	0.0	0	0.0	0	0.0	0	0.0	6	0.6
52	Retail	204	37.5	9	6.9	0	0.0	1	7.4	0	0.0	214	51.9
7832	Movie Theaters	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
6512	Office buildings	206	51.5	52	39.0	0	0.0	0	0.0	0	0.0	258	90.5
8211	Schools	657	61.4	4	3.0	3	4.8	0	0.0	0	0.0	664	69.2
9100	Government Buildings	194	25.1	4	2.6	4	6.0	0	0.0	0	0.0	202	33.7
	Total Cooling Low LF	**1,671**	**219.8**	**70**	**52.0**	**7**	**10.8**	**1**	**7.4**	**0**	**0.0**	**1,749**	**290.1**
	Total Cooling	**2,080**	**274.4**	**92**	**67.9**	**26**	**47.4**	**3**	**31.5**	**0**	**0.0**	**2,201**	**421.2**
	Total C/I All Types	**2,296**	**306.4**	**112**	**81.2**	**31**	**56.5**	**5**	**50.5**	**0**	**0.0**	**2,444**	**494.6**

Table F-5. Arkansas Sector Growth Projections through 2030

SIC Code	Market Sector	2010–2030 Real Growth
20	Food	37.61%
22	Textiles	4.00%
24	Lumber and Wood	1.28%
25	Furniture	1.28%
26	Paper	1.28%
27	Printing/Publishing	4.00%
28	Chemicals	38.35%
29	Petroleum Refining	38.35%
30	Rubber/Misc. Plastics	38.35%
32	Stone/Clay/Glass	40.91%
33	Primary Metals	58.79%
34	Fabricated Metals	58.79%
35	Machinery/Computer Equip	62.98%
37	Transportation Equip.	63.92%
38	Instruments	40.91%
39	Misc. Manufacturing	40.91%
43	Post Offices	32.55%
4581	Airports	66.18%
6512	Office Buildings	92.93%
6513	Apartments	32.55%
7542	Carwashes	13.46%
7832	Movie Theaters	107.27%
8412	Museums	13.46%
4222, 5142	Warehouses	13.46%
4941, 4952	Water Treatment/Sanitary	66.18%
52,53,56,57	Big Box Retail	156.47%
5411, 5421, 5451, 5461, 5499	Food Sales	156.47%
5812	Restaurants	107.27%
7011, 7041	Hotels	107.27%
7211, 7213, 7218	Laundries	13.46%
7374	Data Centers	214.90%
7991, 00, 01	Health Clubs	13.46%
7992, 7997-9904, 7997-9906	Golf/Country Clubs	13.46%
8051, 8052, 8059	Nursing Homes	71.63%
8062, 8063, 8069	Hospitals	71.63%
8211, 8243, 8249, 8299	Schools	71.63%
8221, 8222	Colleges/Universities	71.63%
9100	Government Buildings	33.51%
9223	Prisons	32.55%

Table F-6. CHP Market Segments, Arkansas Existing Facilities and Expected Growth, 2008–2030

Market	50-500 kW MW	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total MW
Traditional High Load Factor Market						
Existing Facilities	121.4	75.8	234.8	214.3	233.4	880
New Facilities	35.7	23.4	73.7	83.3	82.2	298.3
Total	**157.1**	**99.2**	**309**	**298**	**315.6**	**1,178**
Traditional Low Load Factor Market						
Existing Facilities	9.8	0.57	0	0	0	10.37
New Facilities	1.3	0.07	0	0	0	1.37
Total	**11.1**	**0.64**	**0**	**0**	**0**	**11.74**
Cooling CHP High Load Factor Market						
Existing Facilities	54.6	15.8	36.5	24	0	130.9
New Facilities	44.9	14.7	35.8	34.4	0	129.8
Total	**99.5**	**30.5**	**72.3**	**58.4**	**0**	**260.7**
Cooling CHP Low Load Factor Market						
Existing Facilities	219.8	52	10.8	7.4	0	290
New Facilities	212.4	50.6	5.4	11.6	0	280
Total	**432**	**102.6**	**16.2**	**19**	**0**	**570**
Total Market including Incremental Cooling Load						
Existing Facilities	406	144.17	282	245.7	233.4	1,311
New Facilities	294	88.77	114.9	129.3	82.2	709
Total	**700**	**233**	**397**	**375**	**315.6**	**2,020**

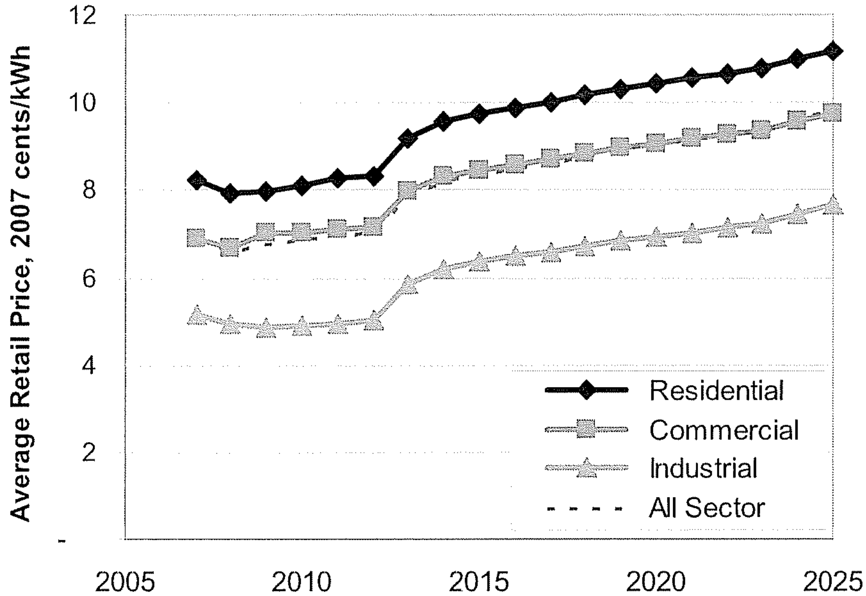
F.2. Energy Price Projections

The expected future relationship between purchased natural gas and electricity prices, called the spark spread in this context, is one major determinant of the ability of a facility with electric and thermal energy requirements to cost-effectively utilize CHP. For this screening analysis, a fairly simple methodology was used:

F.2.1. Electric Price Estimation

The retail electric price forecasts were provided by ACEEE based on a proprietary electric supply model and retail price markups from the EIA 2009 Annual Energy Outlook electric generation price forecast for the Southeast Electric Reliability Council (SERC.). Figure F-1 shows the annual forecast track for major customer groups. The avoidable portion of the retail rate due to baseload CHP operation is assumed to be 90% of the industrial rate. This assumption accounts for unavoidable charges like customer charges, standby rates, and demand charges. Low load factor CHP is assumed to be 17% higher than the baseload rate; avoided electric air conditioning is assumed to be 60% higher. The smallest size category in the analysis, 50-500 kW, is assumed to be 20% higher across the board. These prices are shown in Table F-7.

Figure F-1. Retail Electric Price Forecast



Source: ACEEE Reference Case

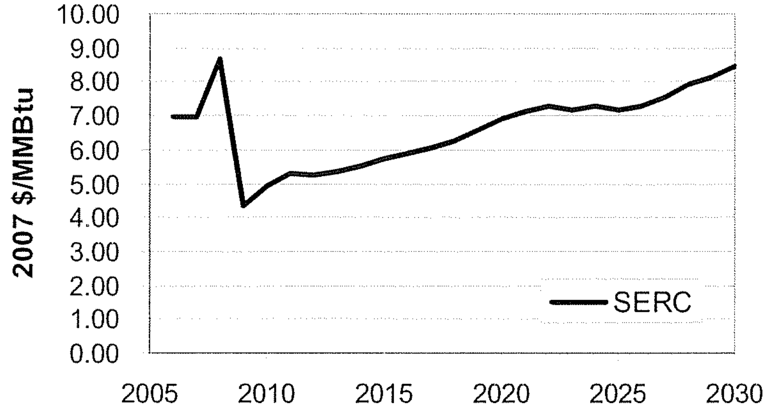
Table F-7. Avoided CHP Electric Rates by Size and Load Factor (2007$)

CHP Size Range	Load Factor	2010–2014	2015–2019	2020–2024	2025–2029
50-500 kW	Baseload	$0.0582	$0.0712	$0.0774	$0.0826
	Low Load Factor	$0.0681	$0.0834	$0.0905	$0.0967
	Avoided AC	$0.1164	$0.1425	$0.1548	$0.1652
Greater than 500 kW	Baseload	$0.0485	$0.0594	$0.0645	$0.0689
	Low Load Factor	$0.0568	$0.0695	$0.0754	$0.0806
	Avoided AC	$0.0970	$0.1187	$0.1290	$0.1377

F.2.2. Natural Gas Price Estimation

Future natural gas prices were estimated from the EIA 2009 AEO SERC region gas price for electric power generation as shown in Figure F-2. This price is assumed to reflect the city-gate price for natural gas. The incremental transportation cost for a process boiler customer adding a 5 MW CHP system is estimated at $1.20/MMBtu. It was assumed that this current price will increase with inflation—that is, it will be constant in real dollars. This mark-up was used for all CHP systems and sizes.

Figure F-2. Natural Gas Price Forecast, SERC Electric Power Generation Price



Source: EIA 2009

F.3. CHP Technology Cost and Performance

The CHP system itself is the engine that drives the economic savings. The cost and performance characteristics of CHP systems determine the economics of meeting the site's electric and thermal loads. A representative sample of commercially and emerging CHP systems was selected to profile performance and cost characteristics in CHP applications. The selected systems range in capacity from approximately 100–40,000 kW. The technologies include gas-fired reciprocating engines, gas turbines, microturbines, and fuel cells. The appropriate technologies were allowed to compete for market share in the penetration model. In the smaller market sizes, reciprocating engines competed with microturbines and fuel cells. In intermediate sizes (1 to 20 MW), reciprocating engines competed with gas turbines.

Cost and performance estimates for the CHP systems were based on work being undertaken for the EPA.[67] The foundation for these updates is based on work previously conducted for NYSERDA,[68] on peer-reviewed technology characterizations that Energy and Environmental Analysis (EEA) developed for the National Renewable Energy Laboratory (NREL 2003) and on follow-on work conducted by DE Solutions for Oak Ridge National Laboratory (ORNL 2004). Additional emissions characteristics and cost and performance estimates for emissions control technologies were based on ongoing work EEA is conducting for EPRI (EPRI 2005). Data is presented for a range of sizes that include basic electrical performance characteristics, CHP performance characteristics (power to heat ratio), equipment cost estimates, maintenance cost estimates, emission profiles with and without after-treatment control, and emissions control cost estimates. The technology characteristics are presented for three years: 2009, 2014, 2019. The 2009–2013 market penetration estimates are based on current 2009 commercially available and emerging technologies. The cost and performance estimates for 2014 and 2019 reflect current technology development paths and currently planned government and industry funding. These projections were based on estimates included in the three references mentioned above. NOx emissions estimates in lb/MWh are presented for each technology both with and without aftertreatment control (AT). For this analysis, aftertreatment costs were included. The installed costs are base on national averages. The cost and performance data are show in Tables F-8 through F-11.

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[67] EPA CHP Partnership Program, Technology Characterizations, December 2007.
[68] *Combined Heat and Power Potential for New York State*, Energy Nexus Group (later became part of EEA), for NYSERDA, May 2002.

Table F-8. Reciprocating Engine Cost and Performance Characteristics

CHP System	Characteristic/Year Available	2009	2014	2019
100 kW-Rich Burn with 3 way catalyst	Installed Costs, $/kW	2,210	1,925	1,568
	Heat Rate, Btu/kWh	12,000	10,830	10,500
	Electric Efficiency, %	28.4	31.5	32.5
	Thermal Output, Btu/kWh	6100	5093	4874
	Overall Efficiency, %	79.3	78.5	78.9
	Power to Heat	0.56	0.67	0.70
	O&M Costs, $/kWh	0.02	0.016	0.012
	NO_x Emissions, lbs/MWh (w/ AT)	0.15	0.15	0.15
	NO_x Emissions, lbs/MWh (w/AT) CHP Credit	0.05	0.06	0.06
	After-Treatment Cost, $/kW	incl.	incl.	incl.

CHP System	Characteristic/Year Available	2009	2014	2019
800 kW-Lean Burn	Installed Costs, $/kW	1,640	1,443	1,246
	Heat Rate, Btu/kWh	9,760	9,750	9,225
	Electric Efficiency, %	35.0	35.0	37.0
	Thermal Output, Btu/kWh	4299	4300	3800
	Overall Efficiency, %	79.0	79.1	78.2
	Power to Heat	0.79	0.79	0.90
	O&M Costs, $/kWh	0.016	0.013	0.011
	NO_x Emissions, gm/bhp (w/o AT)	0.7	0.4	0.25
	NO_x Emissions, lbs/MWh (w/o AT)	2.17	1.24	0.775
	NO_x Emissions, lbs/MWh (w/AT)	0.11	0.12	0.08
	NO_x Emissions, lbs/MWh (w/AT) CHP Credit	0.05	0.05	0.04
	After-Treatment Cost, $/kW	300	190	140
3000 kW-Lean Burn	Installed Costs, $/kW	1,130	1,100	1,041
	Heat Rate, Btu/kWh	9,492	8,750	8,325
	Electric Efficiency, %	35.9	39.0	41.0
	Thermal Output, Btu/kWh	3510	3189	2900
	Overall Efficiency, %	72.9	75.4	75.8
	Power to Heat	0.97	1.07	1.18
	O&M Costs, $/kWh	0.014	0.012	0.01
	NO_x Emissions, gm/bhp (w/o AT)	0.7	0.4	0.25
	NO_x Emissions, lbs/MWh (w/o AT)	2.17	1.24	0.775
	NO_x Emissions, lbs/MWh (w/AT)	0.11	0.12	0.08
	NO_x Emissions, lbs/MWh (w/AT) CHP Credit	0.05	0.06	0.04
	After-Treatment Cost, $/kW	200	130	100

CHP System	Characteristic/Year Available	2009	2014	2019
5000 kW-Lean Burn	Installed Costs, $/kW	1,130	1,099	1,038
	Heat Rate, Btu/kWh	8,758	8,325	7,935
	Electric Efficiency, %	39	41	43
	Thermal Output, Btu/kWh	3046	2797	2605
	Overall Efficiency, %	73.7	74.6	75.8
	Power to Heat	1.12	1.22	1.31
	O&M Costs, $/kWh	0.011	0.01	0.009
	NO_x Emissions, gm/bhp (w/o AT)	0.5	0.4	0.25
	NO_x Emissions, lbs/MWh (w/o AT)	1.55	1.24	0.775
	NO_x Emissions, lbs/MWh (w/AT)	0.11	0.12	0.08
	NO_x Emissions, lbs/MWh (w/AT) CHP Credit	0.06	0.07	0.04
	After-Treatment Cost, $/kW	150	115	80

Table F-9. Microturbine Cost and Performance Characteristics

CHP System	Characteristic/Year Available	2009	2014	2019
65 kW	Installed Costs, $/kW	2,739	2,037	1,743
	Heat Rate, Btu/kWh	13,542	12,500	11,375
	Electric Efficiency, %	25.2	27.3	30
	Thermal Output, Btu/kWh	6277	5350	4500
	Overall Efficiency, %	71.5	70.1	69.6
	Power to Heat	0.54	0.64	0.76
	O&M Costs, $/kWh	0.022	0.016	0.012
	NO_x Emissions, lbs/MWh (w/o AT)	0.17	0.14	0.13
	NO_x Emissions, lbs/MWh (w/o AT) CHP Credit	0.06	0.05	0.06
	After-Treatment Cost, $/kW			
250 KW-use multiple units	Installed Costs, $/kW	2,684	2,147	1,610
	Heat Rate, Btu/kWh	12,290	11,750	10,825
	Electric Efficiency, %	27.8	29	31.5
	Thermal Output, Btu/kWh	4800	4300	3700
	Overall Efficiency, %	66.8	65.6	65.7
	Power to Heat	0.71	0.79	0.92
	O&M Costs, $/kWh	0.015	0.013	0.012
	NO_x Emissions, lbs/MWh (w/o AT)	0.14	0.13	0.13
	NO_x Emissions, lbs/MWh (w/o AT) CHP Credit	0.06	0.06	0.06
	After-Treatment Cost, $/kW			

Table F-10. Fuel Cell Cost and Performance Characteristics

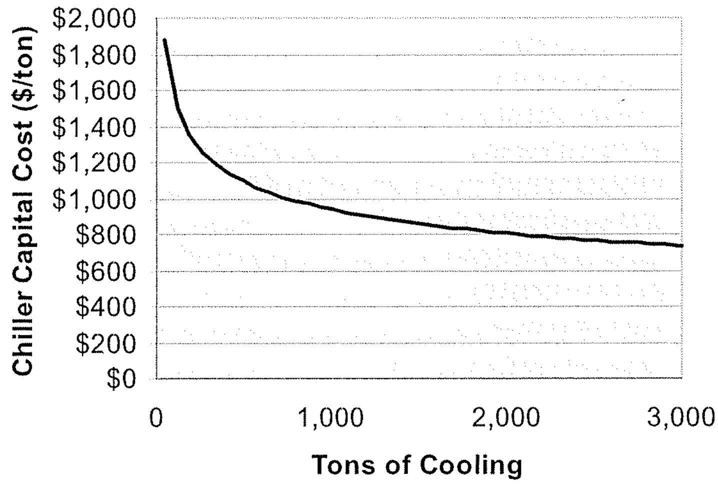
CHP System	Characteristic/Year Available	2009	2014	2019
200/400 kW PAFC (assumes all high grade and 50% low grade thermal utilized)	Installed Costs, $/kW	6,310	4,782	3,587
	Heat Rate, Btu/kWh	9,475	9,475	9,000
	Electric Efficiency, %	36	36	37.9
	Thermal Output, Btu/kWh	2923	2923	2800
	Overall Efficiency, %	66.9	66.9	69
	Power to Heat	1.17	1.17	1.22
	O&M Costs, $/kWh	0.038	0.017	0.015
	NO_x Emissions, lbs/MWh (w/o AT)	0.04	0.035	0.035
	After-Treatment Cost, $/kW	n.a.	n.a.	n.a.
300 kW MCFC	Installed Costs, $/kW	5,580	4,699	3,671
	Heat Rate, Btu/kWh	8,022	7,700	7,300
	Electric Efficiency, %	42.5	44.3	46.7
	Thermal Output, Btu/kWh	1600	1500	1300
	Overall Efficiency, %	62.5	63.8	64.5
	Power to Heat	2.13	2.27	2.62
	O&M Costs, $/kWh	0.035	0.02	0.015
	NO_x Emissions, lbs/MWh (w/o AT)	0.01	0.01	0.01
	After-Treatment Cost, $/kW	n.a.	n.a.	n.a.
1500 kW MCFC	Installed Costs, $/kW	5,250	4,523	3,554
	Heat Rate, Btu/kWh	8,022	7,500	6,820
	Electric Efficiency, %	42.5	45.5	50
	Thermal Output, Btu/kWh	1583	1400	1100
	Overall Efficiency, %	62.3	64.2	66.2
	Power to Heat	2.15	2.44	3.1
	O&M Costs, $/kWh	0.032	0.019	0.015
	NO_x Emissions, lbs/MWh (w/o AT)	0.01	0.01	0.01
	After-Treatment Cost, $/kW	n.a.	n.a.	n.a.

Table F-11. Gas Turbine Cost and Performance Characteristics

CHP System	Characteristic/Year Available	2009	2014	2019
3000 KW GT	Installed Costs, $/kW	1,690	1,560	1,300
	Heat Rate, Btu/kWh	13,100	12,650	11,500
	Electric Efficiency, %	26	27	29.7
	Thermal Output, Btu/kWh	5018	4750	4062
	Overall Efficiency, %	64.4	64.5	65
	Power to Heat	0.68	0.72	0.84
	O&M Costs, $/kWh	0.0074	0.0065	0.006
	NO_x Emissions, ppm (w/o AT)	15	9	5
	NO_x Emissions, lbs/MWh (w/o AT)	0.68	0.38	0.2
	NO_x Emission, lb/MWh (w/AT)	0.07	0.07	0.07
	After-Treatment Cost, $/kW	210	175	150
10 MW GT	Installed Costs, $/kW	1,298	1,278	1,200
	Heat Rate, Btu/kWh	11,765	10,800	9,950
	Electric Efficiency, %	29	31.6	34.3
	Thermal Output, Btu/kWh	4674	4062	3630
	Overall Efficiency, %	68.7	69.2	70.8
	Power to Heat	0.73	0.84	0.94
	O&M Costs, $/kWh	0.007	0.006	0.005
	NO_x Emissions, ppm (w/o AT)	15	9	5
	NO_x Emissions, lbs/MWh (w/o AT)	0.68	0.38	0.2
	NO_x Emission, lb/MWh (w/AT)	0.07	0.07	0.07
	After-Treatment Cost, $/kW	140	125	100
40 MW GT	Installed Costs, $/kW	972	944	916
	Heat Rate, Btu/kWh	9,220	8,865	8,595
	Electric Efficiency, %	37	38.5	39.7
	Thermal Output, Btu/kWh	3189	3019	2892
	Overall Efficiency, %	71.6	72.5	73.3
	Power to Heat	1.07	1.13	1.18
	O&M Costs, $/kWh	0.004	0.004	0.004
	NO_x Emissions, ppm (w/o AT)	15	5	3
	NO_x Emissions, lbs/MWh (w/o AT)	0.55	0.2	0.1
	NO_x Emission, lb/MWh (w/AT)	0.06	0.06	0.06
	After-Treatment Cost, $/kW	90	75	40

In the cooling markets, an additional cost was added to reflect the costs of adding chiller capacity to the CHP system. These costs depend on the sizing of the absorption chiller which in turn depends on the amount of usable waste heat that the CHP system produces. Figure F-3 shows this cost approximation.

Figure F-3. Absorption Chiller Capital Costs



F.4. Market Penetration Analysis

ICF International has developed a CHP market penetration model that estimates cumulative CHP market penetration in 5-year increments. This model evaluates CHP market penetration for natural gas fired systems in commercial, institutional, and industrial applications. For this analysis, only applications that could use the CHP generated electricity on-site were considered. Therefore, the forecast results reflect the opportunity for electrically sized systems fired by natural gas. The potential markets for CHP using opportunity fuels or for large export projects is not included.

For this analysis, the forecast periods are 2014, 2019, 2024, and 2029. These results are interpolated to the output years 2010, 2015, 2020, and 2025. The target market is comprised of the facilities that make up the technical market potential as defined in previously in this section. Thee economic competition module in the market penetration model compares CHP technologies to purchased fuel and power in 5 different sizes and 4 different CHP application types. The calculated payback determines the potential pool of customers that would consider accepting the CHP investment as economic. Additional, non economic screening factors are applied that limit the pool of customers that can accept CHP in any given market/size. Based on this calculated economic potential, a market diffusion model is used to determine the cumulative market penetration for each 5-year time period. The cumulative market penetration, economic potential and technical potential are defined as follows:

- *Technical potential* represents the total capacity potential from existing and new facilities that are likely to have the appropriate physical electric and thermal load characteristics that would support a CHP system with high levels of thermal utilization during business operating hours.

- *Economic potential*, as shown in the table, reflects the share of the technical potential capacity (and associated number of customers) that would consider the CHP investment economically acceptable according to a procedure that is described in more detail below.

- *Cumulative market penetration* represents an estimate of CHP capacity that will actually enter the market between 2009 and 2025. This value discounts the economic potential to reflect non-economic screening factors and the rate that CHP is likely to actually enter the market.

In addition to segmenting the market by size, as shown in the table, the analysis is conducted in four separate CHP market applications (high load and low load factor traditional CHP and high and low load factor CHP with cooling.) These markets are considered individually because both the annual load factor and the installation and operation of thermally activated cooling has an impact on the system economics.

Economic potential is determined by an evaluation of the competitiveness of CHP versus purchased fuel and electricity. The projected future fuel and electricity prices and the cost and performance of CHP technologies determine the economic competitiveness of CHP in each market. CHP technology and performance assumptions appropriate to each size category and region were selected to represent the competition in that size range (Table F-12). Additional assumptions were made for the competitive analysis. Technologies below 1 MW in electrical capacity are assumed to have an economic life of 10 years. Larger systems are assumed to have an economic life of 15 years. Capital related amortization costs were based on a 10% discount rate. Based on their operating characteristics (each category and each size bin within the category have specific assumptions about the annual hours of CHP operation (80-90% for the high load factor cases with appropriate adjustments for low load factor facilities), the share of recoverable thermal energy that gets utilized (80%-90%), and the share of useful thermal energy that is used for cooling compared to traditional heating. The economic figure-of-merit chosen to reflect this competition in the market penetration model is simple payback.[69] While not the most sophisticated measure of a project's performance, it is nevertheless widely understood by all classes of customers.

Table F-12. Technology Competition Assumed within Each Size Category

CHP Market Size	Equivalent Full Load Hours of Use	Thermal Utilization	Competing CHP Technologies
50-500 kW	HiLF = 7,008 LoLF = 4,500	H only Markets 80% H / 0% C H/C Markets 40% H / 40% C	100 kW ICE 65 kW MT 200 kW PAFC
500-1,000 kW	HiLF = 7,008 LoLF = 4,500	H only Markets 80% H / 0% C H/C Markets 40% H / 40% C	800 kW ICE 250 kW MT x 3 300 kW MCFC x 2
1-5 MW	HiLF = 7,008 LoLF = 4,500	H only Markets 80% H / 0% C H/C Markets 40% H / 40% C	3000 kW ICE 3000 kW GT 1500 kW MCFC
5-20 MW	HiLF = 7,446 LoLF = 4,500	H only Markets 90% H / 0% C H/C Markets 45% H / 45% C	5 MW ICE 10 MW GT
>20 MW	HiLF = 8059 LoLF = 4,500	H only Markets 100% H / 0% C H/C Markets 50% H / 50% C	40 MW GT

Abbreviations

Load Factor: HiLF = High load factor, LoLF = Low load factor

Thermal H = heating (boiler replacement)
C = cooling (electric AC replacement)

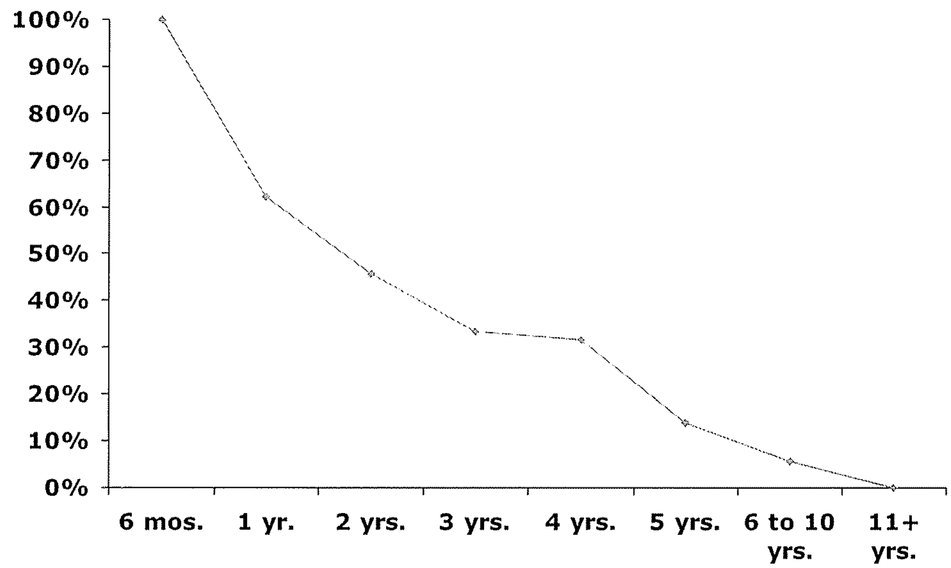
Technology ICE = Internal combustion engine
MT = Microturbine
PAFC = phosphroic acid fuel cell
MCFC = molten carbonate fuel cell
GT = gas turbine

Rather than use a single payback value, such as 3-years or 5-years as the determinant of economic potential, we have based the market acceptance rate on a survey of commercial and industrial facility operators concerning the payback required for them to consider installing CHP. Figure F-4 shows the percentage of survey respondents that would accept CHP investments at different payback levels (CEC

[69] Simple payback is the number of years that it takes for the annual operating savings to repay the initial capital investment.

2005b). As can be seen from the figure, more than 30% of customers would reject a project that promised to return their initial investment in just one year. A little more than half would reject a project with a payback of 2 years. This type of payback translates into a project with an ROI of between 49-100%. Potential explanations for rejecting a project with such high returns is that the average customer does not believe that the results are real and is protecting himself from this perceived risk by requiring very high projected returns before a project would be accepted, or that the facility is very capital limited and is rationing its capital raising capability for higher priority projects (market expansion, product improvement, etc.).

Figure F-4. Customer Payback Acceptance Curve



Source: *Primen's 2003 Distributed Energy Market Survey*

For each market segment, the economic potential represents the technical potential multiplied by the share of customers that would accept the payback calculated in the economic competition module.

The rate of market penetration is based on Bass diffusion curves with allowance for growth in the maximum market. This function determines cumulative market penetration for each 5-year period. Smaller size systems are assumed to take a longer time to reach maximum market penetration than larger systems. Cumulative market penetration using a Bass diffusion curve takes a typical S-shaped curve. In the generalized form used in this analysis, growth in the number of ultimate adopters is allowed. The curves shape is determined by an initial market penetration estimate, growth rate of the technical market potential, and two factors described as internal market influence and external market influence.

The cumulative market penetration factors reflect the economic potential multiplied by the non-economic screening factor (maximum market potential) and by the Bass model market cumulative market penetration estimate.

Once the market penetration is determined, the competing technology shares within a size/utility bin are based on a logit function calculated on the comparison of the system paybacks. The greatest market share goes to the lowest cost technology, but more expensive technologies receive some market share depending on how close they are to the technology with the lowest payback. (This technology allocation feature is part of the ICF CHP model that is not specifically used for this analysis.)

Three cases were run for this analysis:

1. Base Case—no program incentives (Table F-12);

2. $500/kW Incentive—$500/kW capital cost reduction for CHP projects less than 20 MW (Table F-13);

3. $1,000/kW incentive—$1,000/kW capital cost reduction for CHP projects less than 20 MW (Table F-14).

Table F-13. Market Penetration Results for Base Case

CHP Measurement	2010	2015	2020	2025
Cumulative Market Penetration (MW)				
Industrial	0.0	2.2	11.8	16.5
Commercial/Institutional	0.0	0.0	0.0	0.0
Total	0.0	2.2	11.9	16.5
Avoided Cooling	0.0	0.0	0.0	0.0
Scenario Grand Total	**0.0**	**2.2**	**11.9**	**16.5**
Annual Electric Energy (Million kWh)				
Industrial	0.0	17.5	95.5	133.1
Commercial/Institutional	0.0	0.0	0.0	0.0
Total	0.0	17.5	95.5	133.1
Avoided Cooling	0.0	0.0	0.0	0.0
Scenario Grand Total	**0.0**	**17.5**	**95.5**	**133.1**
Incremental Onsite Fuel (billion Btu/year)				
Industrial	0.0	89.1	485.4	672.4
Commercial/Institutional	0.0	0.0	0.1	0.1
Total	**0.0**	**89.1**	**485.4**	**672.5**
Cumulative Investment (million 2007$)	$0.0	$2.3	$12.6	$17.1
Cumulative Incentive Payments (Million 2007$)	$0.0	$0.0	$0.0	$0.0
Annual Electric Energy (Million 2007 $)				
Industrial	$0.0	$1.0	$5.3	$6.7
Commercial/Institutional	$0.0	$0.0	$0.0	$0.0
Total	$0.0	$1.0	$5.3	$6.7
Avoided Cooling	$0.0	$0.0	$0.0	$0.0
Scenario Grand Total	**$0.0**	**$1.0**	**$5.3**	**$6.7**
Incremental Onsite Fuel (million 2007 $)				
Industrial	$0.0	$1.3	$4.1	$6.0
Commercial/Institutional	$0.0	$0.0	$0.0	$0.0
Total	**$0.0**	**$1.3**	**$4.1**	**$6.0**

Table F-14. Market Penetration Results for $500/kW Incentive Case

CHP Measurement	2010	2015	2020	2025
Cumulative Market Penetration (MW)				
Industrial	0.0	2.9	17.0	28.9
Commercial/Institutional	0.0	0.1	0.7	1.7
Total	0.0	3.0	17.7	30.6
Avoided Cooling	0.0	0.0	0.0	0.0
Scenario Grand Total	**0.0**	**3.0**	**17.7**	**30.6**
Annual Electric Energy (Million kWh)				
Industrial	0.0	22.9	133.3	223.7
Commercial/Institutional	0.0	0.7	4.9	12.3
Total	0.0	23.5	138.2	236.1
Avoided Cooling	0.0	0.0	0.0	0.0
Scenario Grand Total	**0.0**	**23.5**	**138.2**	**236.1**
Incremental Onsite Fuel (billion Btu/year)				
Industrial	0.0	117.2	683.6	1147.5
Commercial/Institutional	0.0	3.5	25.7	64.5
Total	**0.0**	**120.7**	**709.3**	**1212.1**
Cumulative Investment (million 2007$)	$0.0	$3.0	$17.1	$27.5
Cumulative Incentive Payments (Million 2007$)	$0.0	$0.4	$2.9	$7.0
Annual Electric Energy (Million 2007 $)				
Industrial	$0.0	$1.4	$6.9	$9.7
Commercial/Institutional	$0.0	$0.0	$0.2	$0.6
Total	$0.0	$1.4	$7.1	$10.3
Avoided Cooling	$0.0	$0.0	$0.0	$0.0
Scenario Grand Total	**$0.0**	**$1.4**	**$7.1**	**$10.3**
Incremental Onsite Fuel (million 2007 $)				
Industrial	$0.0	$1.7	$6.2	$10.5
Commercial/Institutional	$0.0	$0.1	$0.3	$0.6
Total	**$0.0**	**$1.8**	**$6.4**	**$11.1**

Table F-15. Market Penetration Results for $1,000/kW Incentive Case

CHP Measurement	2010	2015	2020	2025
Cumulative Market Penetration (MW)				
Industrial	0.0	15.7	89.6	140.1
Commercial/Institutional	0.0	1.5	9.2	17.6
Total	0.0	17.2	98.8	157.7
Avoided Cooling	0.0	0.0	0.3	0.9
Scenario Grand Total	**0.0**	**17.2**	**99.1**	**158.6**
Annual Electric Energy (Million kWh)				
Industrial	0.0	115.0	656.8	1,026.1
Commercial/Institutional	0.0	9.8	60.8	116.4
Total	0.0	124.8	717.6	1,142.5
Avoided Cooling	0.0	0.1	0.7	2.1
Scenario Grand Total	**0.0**	**124.9**	**718.3**	**1,144.7**
Incremental Onsite Fuel (billion Btu/year)				
Industrial	0.0	614.8	3499.5	5420.3
Commercial/Institutional	0.0	54.6	342.1	669.3
Total	**0.0**	**669.4**	**3841.7**	**6089.6**
Cumulative Investment (million 2007$)	$0.0	$6.2	$34.3	$49.5
Cumulative Incentive Payments (Million 2007$)	$0.0	$15.0	$87.0	$141.2
Annual Electric Energy (Million 2007 $)				
Industrial	$0.0	$6.9	$35.1	$46.6
Commercial/Institutional	$0.0	$0.6	$3.2	$5.0
Total	$0.0	$7.5	$38.3	$51.6
Avoided Cooling	$0.0	$0.0	$0.0	$0.1
Scenario Grand Total	**$0.0**	**$7.5**	**$38.3**	**$51.7**
Incremental Onsite Fuel (million 2007 $)				
Industrial	$0.0	$9.0	$30.8	$48.3
Commercial/Institutional	$0.0	$0.8	$3.3	$6.2
Total	**$0.0**	**$9.8**	**$34.1**	**$54.4**

In the Base Case, 16.5 MW of additional natural gas fired CHP capacity is projected by 2025. This capacity is entirely from the large industrial markets. Adding a $500/kW capital cost reduction incentive increases this market penetration to 30.6 MW with an incentive cost of $7 million. Doubling of the incentive to $1,000/kW increases the 2025 cumulative market penetration to 158.6 MW with an incentive cost of $141 million.

Appendix G—The DEEPER Model and Macroeconomic Analysis

The Dynamic Energy Efficiency Policy Evaluation Routine—or the DEEPER Model—is a 15-sector quasi-dynamic input-output impact model of the U.S. economy. Although an updated model with a new name, the model has a 15-year history of use and development. See, for example, Laitner, Bernow, and DeCicco (1998) and Laitner (2007) for a review of past modeling efforts. The model is generally used to evaluate the macroeconomic impacts of a variety of energy efficiency (including renewable energy) and climate policies at both the state and national level. The national model now evaluates policies for the period 2008 through 2050. Although, the DEEPER Model for the North Carolina specific analysis covers the period between 2009 through 2025. As it is now designed, the model solves for the set of energy prices that achieves a desired and exogenously determined level of greenhouse gas emissions (below some previously defined reference case). Although the model does include non-CO2 emissions and other emissions reduction opportunities, it currently focuses on energy-related CO2 emissions and on the prices, policies, and programs necessary to achieve the desired emissions reductions. DEEPER is an Excel-based analytical tool that consists generally of six sets of key modules or groups of worksheets. These six sets of modules now include:

Global data: The information in this module consists of the economic time series data and key model coefficients and parameters necessary to generate the final model results. The time series data includes the projected reference case energy quantities such as trillion Btus and kilowatt-hours, as well as the key energy prices associated with their use. It also includes the projected gross domestic product, wages and salary earnings, and levels of employment as well as information on key technology cost and performance characteristics. The sources of economic information include data from the Energy Information Administration, the Bureau of Economic Analysis, the Bureau of Labor Statistics, and Economy.com. The cost and performance characterization of key technologies is derived from available studies completed by ACEEE and others, as well as data from the Energy Information Administration's (EIA) National Energy Modeling System (NEMS). One of the more critical assumptions in this study is that alternative patterns of electricity consumption will change and/or defer the mix of investments in conventional power plants. Although we can independently generate these impacts within DEEPER, we can also substitute assumptions from the ICF Integrated Planning Model (IPM) and similar models as they may have different characterizations of avoided costs or alternative patterns of power plant investment and spending.

Macroeconomic model: This set of modules contains the "production recipe" for the region's economy for a given "base year"—in this case, 2006, which is the latest year for which a complete set of economic accounts are available for the regional economy. The I-O data, currently purchased from the Minnesota IMPLAN Group (IMPLAN 2007), is essentially a set of input-output accounts that specify how different sectors of the economy buy (purchase inputs) from and sell (deliver outputs) to each other. In this case, the model is now designed to evaluate impacts for 15 different sectors, including: Agriculture, Oil and Gas Extraction, Coal Mining, Other Mining, Electric Utilities, Natural Gas Distribution, Construction, Manufacturing, Wholesale Trade, Transportation and Other Public Utilities (including water and sewage), Retail Trade, Services, Finance, Government, and Households.

Investment, Expenditures and Energy Savings: Based on the scenarios mapped into the model, this worksheet translates the energy policies into a dynamic array of physical energy impacts, investment flows, and energy expenditures over the desired period of analysis. It estimates the needed investment path for an alternative mix of energy efficiency and other technologies (including efficiency gains on both the end-use and the supply side). It also provides an estimate of the avoided investments needed by the electric generation sector. These quantities and expenditures feed directly into the final demand module of the model which then provides the accounting that is needed to generate the set of annual changes in final demand (see the related module description below).

Price dynamics: There are two critical drivers that impact energy prices within DEEPER. The first is a set of carbon charges that are added to retail prices of energy depending on the level of desired level of emission reductions and also depending on the available set of alternatives to achieve those reductions.

The second is the price of energy as it might be affected by changed consumption patterns. In this case DEEPER employs an independent algorithm to generate energy price impacts as they reflect changed demand. Hence, the reduced demand for natural gas in the end-use sectors, for example, might offset increased demand by utility generators. If the net change is a decrease in total natural gas consumption, the wellhead prices might be lowered. Depending on the magnitude of the carbon charge, the change in retail prices might either be higher or lower than the set of reference case prices. This, in turn, will impact the demand for energy as it is reflected in the appropriate modules. In effect, then, DEEPER scenarios rely on both a change in prices and quantities to reflect changes in overall investments and expenditures.

Final demand: Once the changes in spending and investments have been established and adjusted to reflect changes in prices within the other modules of DEEPER, the net spending changes in each year of the model are converted into sector-specific changes in final demand. This, in turn, drives the input-output model according to the following predictive model:

X = (I-A)-1 * Y

where:

X = total industry output by sector
I = an identity matrix consisting of a series of 0's and 1's in a row and column format for each sector (with the 1's organized along the diagonal of the matrix)
A = the production or accounting matrix also consisting of a set of production coefficients for each row and column within the matrix
Y = final demand, which is a column of net changes in final demand by sector

This set of relationships can also be interpreted as

ΔX = (I-A)-1 * ΔY

which reads: a change in total sector output equals (I-A)-1 times a change in final demand for each sector. Employment quantities are adjusted annually according to exogenous assumptions about labor productivity in each of the sectors (based on Bureau of Labor Statistics forecasts).

Results: For each year of the analytical time horizon, the model copies each set of results into this module in a way that can also be exported to a separate report.

SHAPING OHIO'S ENERGY FUTURE: ENERGY EFFICIENCY WORKS

March 2009

American Council for an Energy-Efficient Economy,
Summit Blue Consulting, ICF International,
and Synapse Energy Economics

ACEEE Report Number E092

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Disclaimer: *While several organizations, including Summit Blue Consulting, ICF International, and Synapse Energy Economics, assisted ACEEE in the completion of this analysis and report, the ultimate viewpoints and recommendations expressed herein are those of ACEEE.*

Contents

EXECUTIVE SUMMARY

The passing of Senate Bill 221 (SB 221), which was signed by Governor Ted Strickland on May 1, 2008, was a landmark event that has positioned Ohio to become a national leader in energy efficiency. SB 221 created an aggressive Energy Efficiency Resource Standard (EERS) mandating that Ohio's investor-owned utilities save at least 22% of electricity consumption by 2025, which our report clearly demonstrates is not only achievable, but can also be accomplished cost-effectively while providing significant job and financial benefits to Ohio's economy. The timing of the legislation is opportune, as rising unemployment and a deepening state budget deficit have shown that Ohio and its consumers are in great need of economic revitalization. Deployed as Ohio's "first fuel," investments in energy efficiency will facilitate this revitalization in three ways: (1) by minimizing employment losses through the creation of new "green collar" jobs; (2) by providing critical financial relief to Ohio's consumers through lower energy bills and stable rates, and; (3) by easing the strain on the state budget through lower state operating costs, enabled by the expansion of energy efficiency into state and local government buildings.

Ohio's current fiscal and economic challenges do not preclude the state from garnering considerable benefits from energy efficiency. Energy efficiency and demand response are the lowest-cost resources available to moderate short-term impacts and are also the quickest to deploy, meaning that efficiency resources begin to generate financial savings for the state and its consumers quickly, which can then be reinvested to further stimulate Ohio's ailing economy. A comprehensive state energy plan is also important in order to effectively leverage the boon of federal funding from the *American Recovery and Reinvestment Act*, which includes $6.3 billion for state and local energy efficiency and clean energy grants. So long as investments in energy efficiency are made prudently and complemented by strong programs and policies, Ohio will be able to alleviate these short-term issues and improve its economic vitality well into the future.

Policy Recommendations

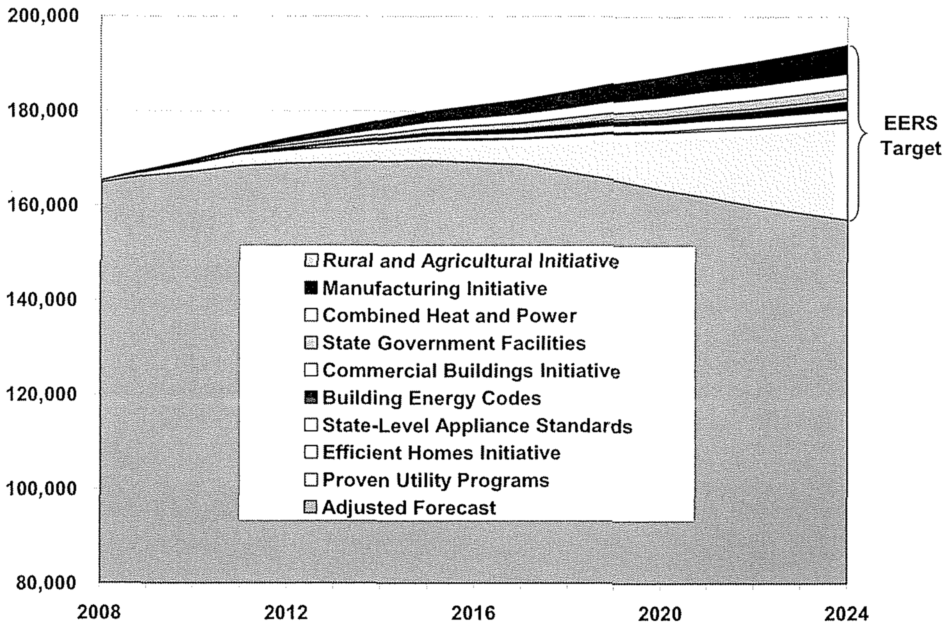
To meet the state's savings targets, ACEEE suggests a suite of ten "innovative" programs and policies (henceforth referred to as "innovative policies" or "policies") in addition to the proven utility program approaches ("programs") that are already beginning to be implemented by the state's utilities. We believe that five of these policies, which could be implemented by utilities or in cooperation with a statewide effort, should be allowed to contribute towards the EERS target. Together these policies and programs would more than satisfy the 22% savings goal; however, we did not attempt to quantify the potential for additional savings beyond the EERS target in this analysis. Our innovative policies are:

A. Energy Efficiency Resource Standard
   1. Advanced Residential Buildings Initiative
   2. Advanced Commercial Buildings Initiative
   3. Manufacturing Initiative
   4. Rural and Agricultural Initiative
   5. Combined Heat and Power

B. Complementary Policies
   6. Workforce Development
   7. State and Local Government Facilities
   8. State-Level Appliance and Equipment Efficiency Standards
   9. Building Energy Codes
   10. Expanded Demand Response Programs

Figure ES-2 shows the contribution of the individual policies and programs towards the EERS target. Our suite of innovative energy efficiency policies will contribute savings of 16,235 GWh, or 10% of Ohio's electricity needs, by 2025. This will leave only 12%, or 20,596 GWh, of the EERS target to be met by the proven programs. In this report we highlight best practice programs that have proven to be effective at reducing electricity consumption in other states across the U.S. With the combination of these innovative policies and proven utility programs, we believe that Ohio can easily satisfy the EERS target cost-effectively and with a net positive benefit to the economy.

Figure ES-1. Share of Projected Electricity Use Met by Innovative Energy Efficiency Policies & Proven Utility Programs



These policy suggestions draw from the best practice policies currently implemented throughout the country. The establishment of Ohio's EERS target represents the core of these policies, providing the foundation upon which the five supporting policies can begin to help achieve the savings goal.

In addition, we find that a suite of demand response (DR) recommendations, which focuses on shifting energy from peak periods to off-peak periods and cutting back electricity needs during periods with the highest needs, is a critical component of reducing peak demand in Ohio. Figure ES-3 presents the combined effects of energy efficiency and demand response on peak reductions.

Economic Potential of Energy Efficiency Resources

This report assesses the total cost-effective, or "economic," potential for energy efficiency investments in Ohio. By characterizing the incremental costs and energy savings for a number of efficient technologies or measures for residential, commercial, and industrial consumers, we determine the cost-effectiveness for each measure and estimate the total energy efficiency "resource" potential. We estimate an economic potential for efficiency resources in Ohio of over 64,000 GWh, or 33% of projected electricity consumption in 2025, as illustrated by Figure ES-3 below. Our results show that contributions from cost-effective resources are not evenly distributed across all sectors, which will necessitate the development and implementation of proven programs that take this weighting into account.

Figure ES-2. Estimated Reductions in Summer Peak Demand through Energy Efficiency and Demand Response (2025 peak reduction = 11,416 MW, or 29%)

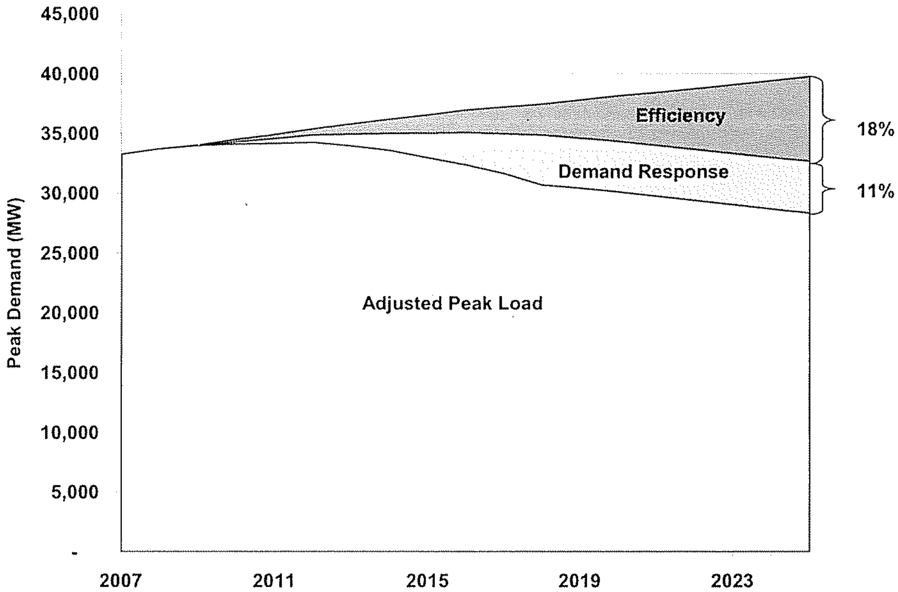
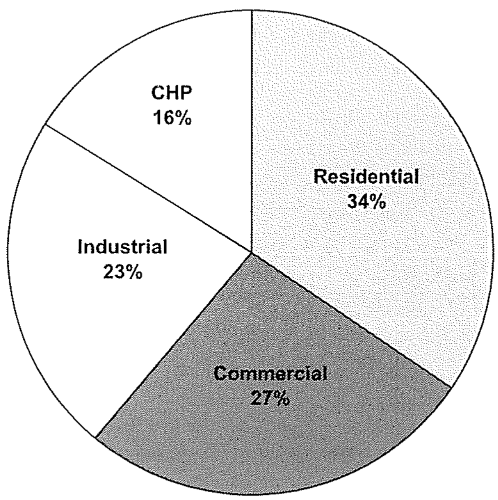


Figure ES-3. Summary of Energy Efficiency Economic Resource Potential (64,284 GWh, or 33% of Projected Electricity Consumption in 2025)



Impacts on Employment and the Economy

The energy savings from these efficiency policies and programs can cut the electricity bills for customers by a net $430 million in 2015. Net annual savings grow eight-fold to $3.3 billion in 2025. While these savings will require some public and customer investment, by 2025 net cumulative savings on electricity bills will reach almost $19 billion. These savings are the result of two effects. First, participants in energy efficiency programs will install energy efficiency measures, such as more efficient appliances or heating equipment, therefore lowering their electricity consumption and electric bills. In addition, because of the current volatility in energy prices, efficiency strategies have the added benefit of improving the balance of demand and supply in energy markets, thereby stabilizing regional electricity prices for the future.

Investments in efficiency policies and programs have the added benefit of creating new, high-quality "green-collar" jobs in Ohio and increasing both wages and Gross State Product (GSP). Our analysis shows that energy efficiency investments can create over 32,000 new jobs in Ohio by 2025 (see Table ES-1), including well-paying trade and professional jobs needed to design, install, and operate energy efficiency measures. These new jobs, including both direct and indirect employment effects, would be equivalent to over 250 new manufacturing facilities relocating to Ohio, but without the public costs for infrastructure or the environmental impacts of new plants.

Table ES-1. Economic Impact of Energy Efficiency Investments in Ohio

Macroeconomic Impacts	2015	2025
Jobs (Actual)	7,928	32,061
Wages (Million $2006)	300	1,615
GSP (Million $2006)	444	2,559

Conclusions

The State of Ohio is poised to make great strides in expanding efficiency throughout the state. As this report documents, there is tremendous potential for Ohio to become a national leader in efficiency and to take advantage of the numerous cost-effective energy efficiency and demand response opportunities that exist in the state. Nonetheless, Ohio does have some difficult decisions to make with regards to its energy future. Faced with severe budgetary constraints and a slumping economy, there may be an inclination to dispel energy efficiency in light of the present conditions. It is therefore extremely important that the momentum created by the establishment of the aggressive EERS target by legislation included in SB 221 not be lost. This legislation has sent a strong signal of Ohio's intent, which in large part contributed to its respectable ranking in ACEEE's 2008 state energy efficiency scorecard. However, Ohio will have to continue to balance its priorities in order for energy efficiency to affect its economy as beneficially as this report highlights.

The various energy efficiency and demand response policies we suggest have been successful in other states in delivering efficiency resources and reducing consumer electric expenditures. We estimate efficiency can meet 122% of the increase in the state's electricity needs over the next 17 years while meeting 188% of the increase in peak demand and reducing emissions by 12%. What is more, these policies and programs can accomplish this at a lower cost than building new supply infrastructure, while simultaneously creating over 32,000 new, high-quality "green collar" jobs by 2025.

Our suggestions are intended to be the starting point for dialog among stakeholders on how to realize the demand-side efficiency resource potential in the state, particularly given the economic challenges it faces. ACEEE's suggestions are based on our review of existing opportunities and stakeholder discussions, and reflect proposals that we think are politically viable. However, it is important to note that these suggestions will not necessarily meet all of the state's future energy needs. While energy efficiency is perhaps the only new energy resource available that can be deployed quickly in the short term and continue to contribute significantly into the long term, the state will still require additional resources to meet the remainder of new load and to replace older, dirtier generation plants as they are retired. Furthermore, additional policies and programs exist that could be implemented to realize even more of the available energy efficiency resources. Ultimately, energy efficiency can delay the immediate need for investments in infrastructure, allowing Ohio the time to rigorously consider its future resource choices.

ACKNOWLEDGMENTS

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ABOUT THE AMERICAN COUNCIL FOR AN ENERGY-EFFICIENT ECONOMY (ACEEE)

ACEEE is a nonprofit organization dedicated to advancing energy efficiency as a means of promoting economic prosperity, energy security, and environmental protection. For more information, see http://www.aceee.org. ACEEE fulfills its mission by:

- Conducting in-depth technical and policy assessments
- Advising policymakers and program managers
- Working collaboratively with businesses, public interest groups, and other organizations
- Organizing conferences and workshops
- Publishing books, conference proceedings, and reports
- Educating consumers and businesses

Projects are carried out by staff and selected energy efficiency experts from universities, national laboratories, and the private sector. Collaboration is key to ACEEE's success. We collaborate on projects and initiatives with dozens of organizations including federal and state agencies, utilities, research institutions, businesses, and public interest groups.

Support for our work comes from a broad range of foundations, governmental organizations, research institutes, utilities, and corporations.

[1] Acknowledgement of support from an entity is not indicative of their sponsorship or endorsement of this report.

GLOSSARY

ENERGY POLICY AND ORGANIZATIONS

(ASHRAE) American Society of Heating, Refrigerating and Air-Conditioning Engineers: Organization of over 50,000 professionals in the air-conditioning, heating, refrigerating and ventilating fields. Support the integration of increased energy efficiency in building design via technological enhancements of these systems (http://www.ashrae.org/).

Avoided Costs: The marginal costs incurred by utilities for additional electric supply resources. Used by utilities to evaluate the cost-effectiveness of energy efficiency programs.

(EERS) Energy Efficiency Resource Standard: A simple, market-based mechanism to encourage more efficient generation, transmission, and use of electricity and natural gas. An EERS consists of electric and/or gas energy savings targets for utilities. All EERS include end-user energy saving improvements that are aided and documented by utilities or other program operators. Often used in conjunction with a Renewable Portfolio Standard (RPS). (See ACEEE's fact sheet for state details: http://aceee.org/energy/state/policies/2pgEERS.pdf.)

(EISA 2007) Energy Independence and Security Act of 2007: Law covering issues from fuel economy standards for cars and trucks to renewable fuel and electricity to training programs for a "green collar" workforce to the first federal mandatory efficiency standards for appliances and lighting.

ENERGY STAR®: A joint program of the U.S. Environmental Protection Agency and the U.S. Department of Energy helping residential customers save money and protect the environment through energy-efficient products and practices (http://www.energystar.gov/). Includes appliance efficiency standards and new building codes.

(EPAct) Energy Policy Act: Law directing U.S. energy policy; first passed in 1992 and major revisions were passed in 2005 and 2007.

(ESCO) Energy Service Company: Provides designs and implementation of energy savings projects. The ESCO performs an in-depth analysis of the property, designs an energy-efficient solution, installs the required elements, and maintains the system to ensure energy savings.

(ESPC) Energy Service Performance Contracting: A financing technique that uses cost savings from reduced energy consumption to repay ESCO's (see above) for the cost of installing energy conservation measures and other services.

(FEMP) Federal Energy Management Program: U.S. Department of Energy program "works to reduce the cost and environmental impact of the Federal government by advancing energy efficiency and water conservation, promoting the use of distributed and renewable energy, and improving utility management decisions at Federal sites" (http://www1.eere.energy.gov/femp/about/index.html).

(FERC) Federal Energy Regulation Commission: Federal agency that "regulates and oversees energy industries in the economic, environmental, and safety interests of the American public" (www.ferc.org).

(IRP) Integrated Resource Plan: A comprehensive and systematic blueprint developed by a supplier, distributor, or end-user of energy who has evaluated demand-side and supply-side resource options and economic parameters and determined which options will best help them meet their energy goals at the lowest reasonable energy, environmental, and societal cost (http://www.energycentral.com/centers/knowledge/glossary/home.cfm).

(LIHEAP) Low-Income Home Energy Assistance Program: A federally funded program intended to assist low-income households that pay a high proportion of household income for home energy, primarily in meeting their immediate home energy needs.

(NERC) North American Electric Reliability Corporation: NERC's mission is to improve the reliability and security of the bulk power system in North America. To achieve that, NERC develops and enforces reliability standards; monitors the bulk power system; assesses future adequacy; audits owners, operators, and users for preparedness; and educates and trains industry personnel. NERC is a self-regulatory organization that relies on the diverse and collective expertise of industry participants. As the Electric Reliability Organization, NERC is subject to audit by the U.S. Federal Energy Regulatory Commission and governmental authorities in Canada (www.nerc.com).

GENERAL REPORT TERMINOLOGY

Cumulative Savings: Sum of the total annual energy savings over a certain time frame.

Demand Side Management (DSM): Programs that focus on minimizing energy demand by influencing the quantity and use-patterns of energy consumption by end users, as opposed to supply side management, which focuses on investments in system infrastructure.

Energy Efficiency: The implementation of programs and policies that minimize the consumption of energy resources while stimulating economic growth.

Incremental Annual Savings: Energy savings occurring in a single year from the current year programs and policies only.

Percent Turnover: Percentage of technology replaced on burnout with more efficient technology. Does not include retrofits.

Potential: amount of energy savings possible

- **Achievable Potential**: Potential that could be achieved through normal market forces, new state building codes, equipment efficiency, and utility energy efficiency programs
- **Economic Potential**: Potential based on both the Technical Potential and economic considerations (e.g., system cost, avoided cost of energy)
- **Technical Potential:** Potential based on technological limitations only (no economic or other considerations)

Replace-on-Burnout: The act of waiting until a technology's end of life before replacing it with a more energy-efficient technology. Cost basis is the incremental cost of choosing a more efficient technology over a less efficient one. Incremental cost usually means incremental equipment cost with no labor cost; that is, there is no labor cost or it is the same in both cases and thus a zero-sum.

Retrofit Measure: The act of replacing a technology with a more energy-efficient technology before its end of life. Cost basis is the full cost of the new technology, including installation.

Total Annual Savings: Energy savings occurring in a single year from the current year programs and policies and counting prior year savings. Sum of all Incremental Annual Savings.

INDUSTRY and BUILDINGS TECHNOLOGY

(CHP) Combined Heat and Power: method of using waste heat from electrical generation to offset traditional process or space heating. Also called cogeneration (cogen).

Electricity Use Feedback: System that monitors home/building electricity use and provides real time feedback to occupants. This allows occupants to increase energy efficiency.

ENERGY STAR® New Homes: 15% electricity savings over a comparable size home.

HVAC: Heating, ventilation, and air conditioning system.

(NAICS) **North American Industry Classification System**: 6-digit code used to group industries by product.

UTILITY TERMS

Coincidental Peak: The sum of two or more peak loads that occur in the same time interval.

Coincidental Peak Factor: The ratio of annual peak demand savings (kW) from an energy-efficiency measure to the annual energy savings (kWh) from the measure; also called Coincidence Factor.

Demand Response: The reduction of customer energy usage at times of peak usage in order to help address system reliability, reflect market conditions and pricing, and support infrastructure optimization or deferral. Demand response programs may include dynamic pricing/tariffs, price-responsive demand bidding, contractually obligated and voluntary curtailment, and direct load control/cycling.

Deregulation: Allows a rate payer to choose other electricity providers over a local provider. Deregulation efforts vary from reducing to completely eliminating a local monopoly on electricity.

Distributed Energy Resource: Electrical power generation or storage located at or near the point of use, as well as demand-side measures

Distributed Generation: Electric power generation located at or near the point of use.

Distributed Power: Electrical power generation or storage located at or near the point of use.

Electricity Distribution: Regulating voltage to usable levels and distributing electricity to end-users from substations

Electricity Generation: Converting a primary fuel source (e.g., coal, natural gas, or wind) into electricity.

Electricity Transmission: Transport of electricity from the generation source to a distribution substation, usually via power lines.

Henry Hub: The market price for natural gas is by convention set at the Henry Hub (which is a physical location in southern Louisiana where a number of pipelines from the Gulf of Mexico originate). Futures and spot market contracts for delivery of gas are traded on the New York Mercantile Exchange (NYMEX) with regional wholesale prices set at key hubs where pipelines originate or come together. These prices are set relative to the Henry Hub price with adders for transportation and congestion.

(IOU) Investor-Owned Utility: Also known as a private utility, IOU's are utilities owned by investors or shareholders. IOU's can be listed on public stock exchanges.

(ISO) Independent System Operator: Entity that controls and administers nondiscriminatory access to electric transmission in a region or across several systems, independent from the owners of facilities.

Levelized Cost: The level of payment necessary each year to recover the total investment and interest payments at a specified interest rate over the life of the measure.

(MISO) Midwest Independent System Operator: The Midwest ISO is an independent, nonprofit organization that supports the constant availability of electricity in 15 U.S. states and the Canadian province of Manitoba.

Peak Demand: The highest level of electricity demand in the state measured in megawatts (MW) during the year.

Peak Shaving: Technologies or programs that reduce electricity demand only during peak periods (frequently combined with "valley filling" policies that shift consumption to periods of low demand. The combination is referred to as load shifting.)

PJM: PJM Interconnection is a Regional Transmission Organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

Power Pool: Two or more inter-connected electric systems planned and operated to supply power in the most reliable and economical manner for their combined load requirements and maintenance programs.

Renewable Generation: Electric power generation from a renewable energy source such as wind, solar, sustainably harvested biomass, or geothermal.

(RTO) Regional Transmission Organization: An independent regional transmission operator and service provider that meets certain criteria, including those related to independence and market size. Controls and manages the transmission and flow of electricity over large areas.

(REC) Rural Electric Cooperative: REC's are nonprofit, cooperative utilities that provide electricity to rural areas and are owned by all customers of that utility.

Transformer: Electrical device that changes the voltage in AC circuits from high-voltage transmission lines to low voltage distribution lines.

Wholesale Competition: A system in which a distributor of power would have the option to buy its power from a variety of power producers, and the power producers would be able to compete to sell their power to a variety of distribution companies.

Wholesale Electricity: Power that is bought and sold among utilities, non-utility generators, and other wholesale entities, such as municipalities.

Wholesale Power Market: The purchase and sale of electricity from generators to resellers (that sell to retail customers) along with the ancillary services needed to maintain reliability and power quality at the transmission level.

INTRODUCTION

The State of Ohio is one of the nation's largest users of electricity, led only by Texas, Florida, and California. Consumption in the state is projected to grow at an average annual rate of 1% between 2008-2025, and peak demand, a measure of consumption during the hottest periods of the year, is estimated to grow at 1% over that same period.[2] While these growth rates are relatively modest, the dual shocks of a slumping economy and volatile energy markets are placing an inordinate amount of financial pressure on Ohio's electricity consumers. As an added concern, rate stabilization plans (RSP) – introduced in 2006 to help moderate Ohio's transition to a deregulated electricity market – are scheduled to expire at the end of the year, which most anticipate will herald higher retail rates without intervention from utilities and their regulatory body, the Public Utilities Commission of Ohio (PUCO).

On May 1, 2008, Governor Ted Strickland signed Senate Bill (SB) 221, which included legislation mandating investments in energy efficiency and renewable energy intended to alleviate these issues, while also bolstering Ohio's workforce, cleaning its air, and leading the state down a path towards greater energy independence and sustainability. This laudably aggressive target, which through a state Energy Efficiency Resource Standard (EERS) requires investor-owned utilities to accumulate 22% reductions in electricity consumption by 2025, sets the foundation for Ohio to become a national leader in energy efficiency. Unfortunately, the collapse of financial markets and the subsequent economic recession have magnified the ramifications of the state's current budget deficit, leading many to question how Ohio and its consumers will be able to fund these investments and, ultimately, meet the 22% target.

Our report demonstrates that through a combination of innovative policies and proven utility programs, meeting the 22% target is, in fact, achievable and can be accomplished cost-effectively while concomitantly providing significant job and financial benefits to Ohio's economy. Energy efficiency and demand response can provide critical relief from short-term market impacts as they represent the least-cost resources available and are the quickest to deploy. During a time when Ohio's tax revenues are falling and its unemployment is rising, this central tenet is extremely important. And unlike supply-side energy resources, efficiency and demand response are the only resources that can begin to reduce electric bills by decreasing overall consumption, which will save the state and its consumers money that can then be reinvested in Ohio's ailing economy.

Ohio will also have assistance from federal funding to supplement its efficiency investments. On February 17, 2009, President Obama signed the economic stimulus bill, titled the *American Recovery and Reinvestment Act*, which includes $6.3 billion for state and local energy efficiency and clean energy grants. If these funds are invested prudently, it will be possible to reap benefits into the long term, especially if these resources are allocated to supporting policies like workforce education and training, energy-service performance contracting, and weatherization programs. With diligence, energy efficiency has the potential to help Ohio weather the current economic maelstrom, improving the vitality of its economy well into the years ahead.

The goal of this study is to inform policymakers and stakeholders of the opportunities for energy efficiency and demand response in Ohio, and also to suggest policies Ohio could implement to facilitate the development of these clean energy resources. We present the results in a fashion designed to help educate policymakers and the general public about the importance of energy efficiency and demand response, as well as to influence policy development in Ohio over the next several years by identifying policy and technical opportunities for achieving major energy efficiency benefits and savings.

This report is organized into the following sections:

[2] These estimates were made before the current economic downturn and may overproject near-term growth, but in the long term we anticipate increasing growth in consumption as the economy recovers.

- ***Background:*** Reviews the electricity market in Ohio, including recent actions and future opportunities regarding energy efficiency and demand response.

- ***Project Overview and Methodology:*** Provides a context for ACEEE's work with state-level energy efficiency and demand response potential studies and an overview of both the project approach and analysis methodology.

- ***Reference Case:*** Discusses the reference case electricity, peak demand, and price forecasts used in this analysis.

- ***Energy Efficiency Resource Assessment:*** Estimates the cost-effective potential, from the customer's perspective, for increased energy efficiency in the state's residential, commercial, and industrial sectors by 2025 through the adoption of specific energy-efficient technology measures. The resource assessment goes beyond what the state can achieve through penetration of specific programs and policies.

- ***Energy Efficiency Policy Analysis:*** Outlines the recommended policies for Ohio to adopt to tap into the energy efficiency resource potential. This section presents the electricity and peak demand impacts from energy efficiency, the associated costs, and an evaluation of program costs using two cost-effectiveness tests (TRC and the Participant Cost tests). Also included in this section is an estimation of carbon dioxide emissions impacts.

- ***Demand Response Analysis:*** Estimates the potential for increased demand response in Ohio and makes specific recommendations to the State.

- ***Macroeconomic Impacts:*** Estimates the impact of energy efficiency policies on Ohio's economy, employment, and energy prices.

In addition, we provide details and references to resources on most of these sections in the technical appendices that accompanies the body of this report.

BACKGROUND

In 2007, Ohio sold over 161,000 GWh, making it the nation's fourth-largest consumer of electricity. The industrial sector accounts for the greatest share of electricity consumption (36%), though the residential (33%) and commercial sectors (30%) retain only a slightly smaller share (EIA 2008a).[3] Ohio generates about 86% of its electricity from coal, almost twice the national average (see Figure 2). As a result, Ohio is the nation's largest emitter of sulfur dioxide and ranks second in both nitrogen and carbon dioxide emissions (EIA 2007b). In this section we discuss the current condition of the Ohio electricity market and the overall role of energy efficiency and related opportunities to meet the state's energy needs.

Ohio Electricity Market

In 2007, Ohio generated 156,069 GWh of electricity yet consumed 161,547 GWh, making the state a net importer of more than 3% of its electricity generation (see Figure 1). Two regional transmission organizations (RTO) service utilities in the state: the Midwest Independent Transmission System Operator (MISO) and the PJM Interconnection (PJM), allowing Ohio utilities to purchase or sell electricity on the wholesale market.[4] The vast majority of this in-state generated electricity comes

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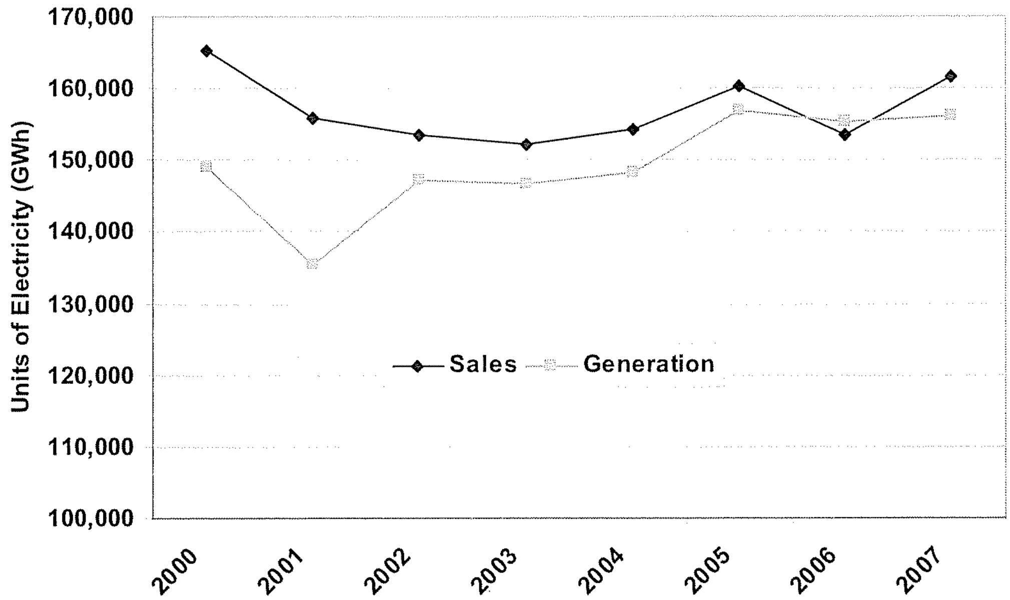
[3] We do not cover the transportation sector in this analysis since the sector's consumption of electricity is negligible relative to the other economic sectors (for a discussion of state-level opportunities for increased efficiency in the transportation sector, see Geller et al. 2007).

[4] FirstEnergy and Duke Energy are members of MISO. AEP and DP&L are members of PJM.

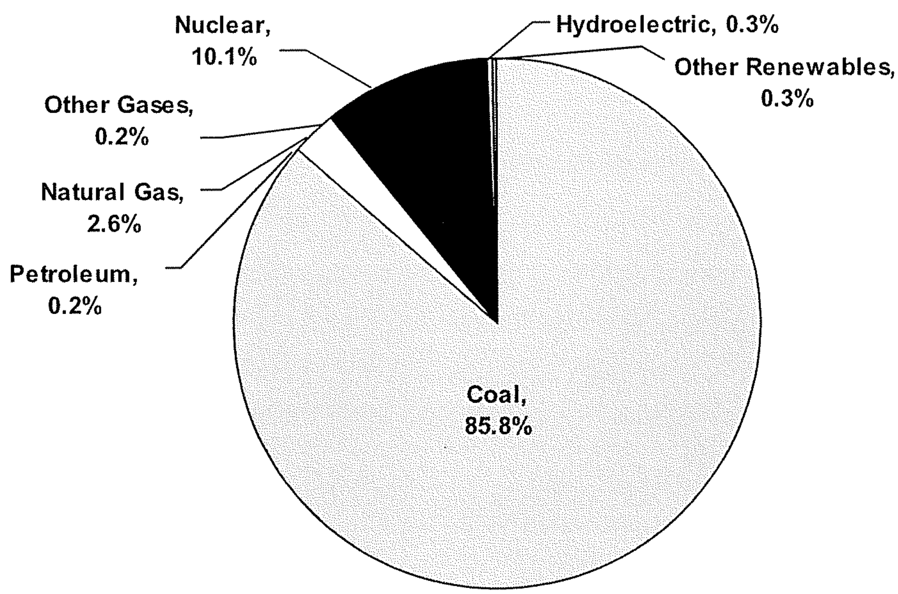
from coal (86%) and nuclear (10.1%) (see Figure 2). By comparison, the national average mix of electricity generation is 49% coal and 19% nuclear (EIA 2007b).

Figure 1. Electricity Sales and Generation in Ohio, 2000-2006



Source: EIA 2008a

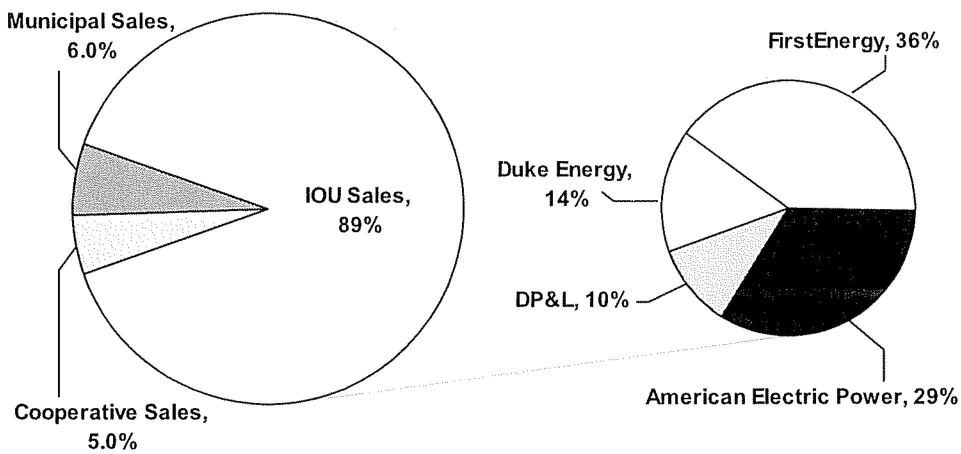
Figure 2. 2007 Ohio Electricity Generation by Fuel Type
Total Generation: 156,069 GWh



Source: EIA 2008a

Electricity is delivered in Ohio to consumers by three types of providers: investor-owned utilities (IOUs), rural electric cooperatives, and municipal electric suppliers. As can be seen in Figure 3, of the three types of providers, IOUs dominate sales in the state (89%), the two largest being FirstEnergy (36%) and AEP (29%). Duke Energy and Dayton Power & Light retain 14% and 10% of the market, respectively. Cooperatives and municipal utilities account for the remaining 11% of sales.

Figure 3. Electricity Deliveries (GWh) by Supplier in 2006



Source: EIA 2007a

The gradual introduction of deregulation starting in 2001 never had the impact on competition that was envisioned, which is evident by the fact that 86% of electricity services remain bundled, while only 8% is delivered to a third party for distribution.

Deregulation of Ohio's Electricity Market

As many states did when faced with rising electricity rates in the mid- to late-1990's, Ohio embraced deregulation in hopes of lowering retail rates for its customers. In 1999, Senate Bill (SB) 3 was passed with the intention of introducing competition into Ohio's electricity market, beginning in 2001. Included in the legislation was the imposition of a five-year market-development period where utility rates were frozen in order to facilitate competition in the market. Competition, however, failed to materialize, and as the end of the development period grew nearer, there was growing concern that the removal of rate caps would effectuate dramatic hikes in retail rates. The Public Utilities Commission of Ohio (PUCO) began to work with utilities to devise Rate Stabilization Plans (RSP) to guarantee stable, predictable rates. Most of these RSP's expire at the end of 2008, which, unattended, will leave Ohio consumers at the mercy of the market.[5]

To address this issue, legislation was included in SB 221 essentially weakening the state's commitment to deregulation in an effort to protect consumers from impending rate increases.[6] The bill requires all utilities to file a standard service offer, effective January 1st, 2009, which determines how utilities' retail rates will be set. A utility can choose between two methods to set its rates: an Electric Security Plan (ESP) or a Market Rate Option (MRO). Initially, however, all investor-owned utilities

[5] The PUCO approved Dayton Power & Light's current rate plan to extend through 2010.
[6] Please see Sections 4928.141 through 4928.143 of SB 221 for more information.

must *at least* file for an ESP, where retail rates are regulated by the PUCO. In conjunction with, or after, this initial filing, a utility may also choose to file for a Market Rate Option (MRO), where its retail rate would reflect prices in the PJM and MISO wholesale markets.[7]

By providing two ways for utilities to set their retail electricity rates, the PUCO is searching for the least-cost option: that being the plan most likely to present customers with the lowest rate. FirstEnergy was the only utility to file for an MRO, which they filed for simultaneously with their ESP, but the MRO was rejected by the PUCO on November 25, 2008 (PUCO 2008). No other Ohio utilities have shown interest in filing for an MRO. Unlike MROs, ESPs, with retail prices regulated by the PUCO, offer greater stability in prices and therefore ensure that the utilities will earn a favorable rate of return while also allowing them to recuperate any losses due to rising fuel costs.

It was believed that deregulation would produce lower retail rates by fostering competition, but since deregulation has failed to meet those expectations, the PUCO now offers these alternative methods of setting rates in the interest of Ohio customers. Nonetheless, because Ohio's electricity market remains deregulated – albeit in principle rather than in fact – when filing for an ESP, utilities are required to show that rates set by an ESP will be favorable to those set by an MRO. Additionally, for those utilities that have had an ESP approved by the PUCO that exceeds a three-year period, the PUCO requires that the ESP be reviewed every fourth year to ensure that the rates being delivered are still favorable when compared to an MRO.[8]

Utility-Level Projects

There are several major generation projects transpiring in Ohio that are aimed at meeting growing demand. The Haverhill North Coke Company completed construction of its Haverhill Generating Facility in August 2008 and began operation on December 1st, 2008. The 61 MW cogeneration facility, located in Haverhill, uses waste heat from coke ovens to generate electricity and has a maximum capacity of 75 MW. The Fremont Energy Center, owned by FirstEnergy and currently under construction in the Sandusky Township, is a 540 MW natural gas-fired combined-cycle electric generating facility with peaking capabilities of 704 MW that is scheduled to begin commercial operations in 2009. American Electric Power's (AEP) Dresden Energy Facility, also slated to begin commercial operations in 2009 and located in the Cass Township, is a 500 MW combined-cycle gas turbine, also with peaking capabilities of 704 MW (OPSB 2008a, 2008b).

Five other generation projects have been approved by the Ohio Power Siting Board (OPSB) and are in varying states of completion. Construction of the Lima Energy IGCC Station, a 580 MW base load synthetic gas plant owned by the Lima Energy Company, has been halted temporarily. Calpine Corporation's Lawrence Energy Center, an 850 MW combined-cycle gas facility, and AEP's Great Bend IGCC station have also been suspended. Construction of American Municipal Power's (AMP) 960 MW coal-fired generating station in Meigs County is scheduled to begin in the second quarter of 2009, though a request to modify a condition in its certificate is currently under investigation (OPSB 2008a, 2008b). The 135 MW FDS Coke Plant Co-Generation Facility in Toledo was approved by the OPSB October 28, 2008 and, according to their Web site, will take two years to complete (OPSB 2008a; FDS 2008).

[7] Utilities that file for an MRO and directly own, in whole or in a part, generating facilities are required to phase in the new rates, gradually transitioning to 100% market-based rates. In the first year, 90% of the new rates would be determined by the ESP and 10% would reflect the market price, ratcheting up the MRO portion each year. Ohio utilities that own their own generating facilities include American Electric Power, Dayton Power & Light, and Duke.

[8] Section 4928.143 (C) (1) of SB 221 requires utilities to conduct their own electricity price forecasts for the purposes of reviewing the benefits of an ESP versus an MRO. This has caused some concern as there is an incentive for utilities to exaggerate their price forecasts in order to make the ESPs appear more economically beneficial.

Role of Energy Efficiency

Ohio has already begun to take significant steps towards promoting energy efficiency. This momentum is vital given the bleak economic conditions and the pending expiration of RSPs, as well as the fact that Ohio generates 86% of its electricity through coal-fired power plants with no plans of reducing that mixture in the foreseeable future (OPSB 2008a). Energy efficiency has the potential to provide short- and long-term economic and social benefits to Ohio consumers, such as lowering consumer bills, abating emissions, and stimulating the economy. Though electricity is forecast to grow at a modest annual average of 1%, deploying energy efficiency in the short term will greatly reduce the need for investing in infrastructure to maintain current services and to meet growing demand in the future.

Ohio's efforts to advance energy efficiency are captured in ACEEE's *2008 State Energy Efficiency Scorecard*, which ranks states on eight energy efficiency policy and performance criteria. Ohio tied for the 18th spot in our *2008 Scorecard*, aided by recent developments that helped Ohio jump eight spots relative to our *2006 Scorecard*, giving it the rank of the third most-improved.[9] Ohio is one of the leading states dedicated to expanding combined heat and power (CHP) and, in fact, tied for 1st in the category (Eldridge et al. 2008). Ohio also provides financial incentives for energy efficiency in the form of grants for industrial efficiency projects, equal to 25% of the project cost with a maximum of $50,000 (DSIRE 2008).

Of particular importance was the introduction of SB 221 on May 1st, 2008, which included legislation encouraging the advancement and growth of alternative energy resources, specifically renewable energy and energy efficiency. SB 221 mandates an Energy Efficiency Resource Standard (EERS), which requires utilities to accumulate savings of at least 22% of consumption by 2025. Currently eighteen states have adopted some form of an EERS and of those eighteen, Ohio's EERS ranks among the more stringent (Eldridge et al. 2008). Effective as of January 1st, 2009, the annual savings target begins at 0.3% and ramps up 0.1–0.2% every year until 2014, where the target increases by 1% annually until 2019 and by 2% annually through 2024.[10] Utilities are also required to implement peak demand reduction programs beginning in 2009. Peak demand savings are targeted at 1% in the first year, followed by a 0.75% annual increase until 2018.[11]

The movement to incorporate energy efficiency is also being fostered by Ohio's utilities. Several utilities offer financial incentives for the purchase and installation of energy-efficient appliances and energy-efficient home improvements. Cleveland Electric Illuminating Co., Ohio Edison, and Toledo Edison – all subsidiaries of FirstEnergy – offer rebates to contractors and homeowners under the auspices of the Home Performance with ENERGY STAR program. FirstEnergy's rebate programs cover rebates on HVAC equipment and appliances, as well as investments in the weatherization of the home envelope. Duke Energy also offers rebates to both homeowners and contractors through its Smart Saver program, but its rebates extend only to HVAC equipment (DSIRE 2008).[12]

In leading states, energy efficiency is meeting 1–2% of the state's electricity consumption each year (Nadel 2007; Hamilton 2008) at a average cost of about 3¢ per kWh (Kushler, York, and Witte 2004),

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[9] Ohio and Maryland tied for third, both having jumped eight spots relative to our *2006 Scorecard*.
[10] The baseline for calculating savings is the average of total kilowatt hours utilities sold during the preceding three years.
[11] While the EERS target set forth in SB 221 directs utilities to accumulate savings of at least 22% of consumption by 2025, the actual requirement specifies annual savings for each year based on a percentage of the average consumption in the prior three years. While the annual percent energy savings targets sum to 22.2% in 2025, the application of the formula specified in the legislation result in a savings of 36,831 GWh in 2025, which represents just under 19% savings relative to the reference forecasted electricity consumption used in this report.
[12] For more information on these utility rebate programs, please visit the Database of State Incentives for Renewables and Efficiency (DSIRE) at www.dsireusa.org.

compared with a utility avoided cost of about 5–10¢ per kWh in Ohio (see Figure 7).[13] States across the country, including California, Connecticut, Massachusetts, Minnesota, New York, and Vermont, are realizing the benefits of energy efficiency today, having enacted policies and programs that effectively tap into their energy efficiency resources. Results from these states show that energy efficiency represents an immediate low cost, low risk strategy to help meet the state's future electricity needs (York, Kushler, and Witte 2008).

Together, energy efficiency and demand response can delay the need for expensive new supply in the form of generation and transmission investments (Elliott et al. 2007; 2007b), thus keeping the future cost of electricity affordable for the state and freeing up energy dollars to be spent on other resources that expand the state's economy. In addition, a greater share of the dollars invested in energy efficiency go to local companies that create new jobs compared with conventional electricity resources, where much of the money flows out of state to equipment manufacturers and energy suppliers.

PROJECT APPROACH AND METHODOLOGY

Stakeholder Engagement

Awareness of the demographics and political climate in the State of Ohio was an integral part of the formulation of the policies that we are suggesting. Each State in the Union is different and we do not presume that any one policy will work ubiquitously. Identifying and engaging stakeholders in Ohio, therefore, was imperative to the relevance and success of our report. We endeavored to meet in person with as many different representative groups as possible in order to better understand Ohio's specific energy structure and needs. For those we were unable to meet with personally, we conducted telephone conferences to facilitate the process. We met with several environmental groups, the PUCO, the Ohio Consumers Council (OCC), the Ohio Department of Development (ODOD), the Ohio Manufacturers Association (OMA), the Ohio Hospital Association (OHA), as well as many of the utilities, such as AEP, Buckeye Power, and American Municipal Power Ohio (AMP Ohio).[14]

One theme that surfaced quite regularly was the necessity of a trained, qualified workforce with which to implement, operate, and evaluate energy efficiency programs. These include positions such as contractors, building operators, auditors, etc. Our stakeholders were particularly emphatic about the need for properly trained workers to conduct evaluation, measurement and verification (EM&V) of efficiency programs. However, considering the high demand for these types of workers at the national level, Ohio is struggling to find qualified firms or individuals to meet its indigenous needs. Efforts to expand the workforce will therefore have to be done within the state through the cooperation of entities such as the Ohio Board of Regents, the PUCO, and the ODOD. Fortunately there are already programs in Ohio that serve the state in this capacity. We will discuss the workforce issue in greater detail in the section discussing our innovative policies.

Analysis Methodology

The following is a description of the energy efficiency analysis methodology:

- ***Reference Case Forecasts:*** The first step in conducting an energy efficiency potential study for Ohio is to collect data and to characterize the state's current and expected patterns of electricity consumption over the time period of the study (2009-2025). In the next section of this report we describe the assumed reference forecasts for electricity and

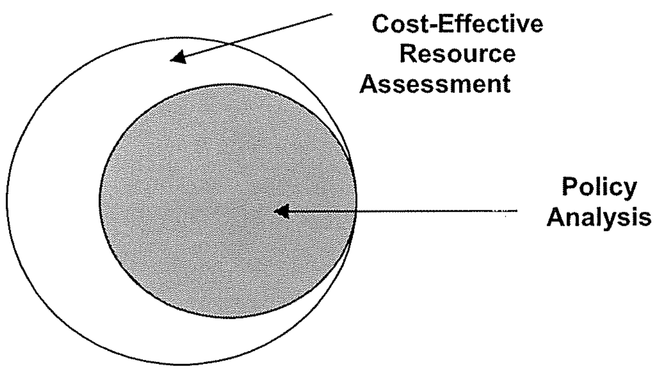
[13] The avoided cost analysis does not take into account a cost of carbon that would be imposed under a federal cap and trade program.
[14] This list is not intended to be exhaustive, but merely indicative of the steps we have taken to ensure that we incorporate the insight of as many different interest groups as possible.

peak demand. Reference case avoided costs for electric utilities, developed by Synapse Energy Economics, are described in this section along with projections of retail energy price forecasts.

- ***Energy Efficiency Resource Assessment:*** The energy efficiency resource assessment examines the overall potential in the state for increased cost-effective efficiency using technologies and practices of which we are currently aware (see Figure 4). Cost-effectiveness is evaluated from the customer's perspective (i.e., a measure is deemed cost-effective if its cost of saved energy is less than the average retail rate of energy). We review specific, efficient technology measures that are technically feasible for each sector; analyze costs, savings, and current market share/penetration; and estimate total potential from implementation of the resource mix. The technology assessment is reported by sector (i.e., residential, commercial, and industrial) and includes an analysis of potential for expanded CHP, which is prepared by ICF International.

- ***Energy Efficiency Policy Analysis:*** For this analysis, we develop a suite of energy efficiency policy recommendations based on successful models implemented in other states and in consultation with stakeholders in Ohio. This analysis assumes a reasonable program and policy penetration rate, and therefore is less than the overall resource potential (see Figure 4). We draw upon our resource assessment and evaluations of these policies in other states to estimate the energy savings and the investments required to realize the savings. The draft policy list for stakeholder review is presented after the reference forecast section in this document.

Figure 4. Levels of Energy Efficiency Potential Analysis



- ***Demand Response (DR) Analysis:*** The Demand Response Analysis, which is prepared by Summit Blue Consulting, assesses current demand response activities in Ohio, uses benchmark information to assess the potential for expanded activities in the state, and offers policy recommendations that could foster DR contributing appropriately to the resource mix in Ohio that could be used to meet electricity needs. Potential load reductions are estimated for a set of DR programs that represent the technologies and customer types that span a range of DR efforts, and are in addition to the demand reductions resulting from expanded energy efficiency investments.

- ***Macroeconomic Impacts:*** Based on the energy savings, program costs, and investment results from the policy analysis, we will then run ACEEE's macroeconomic model, DEEPER, to estimate the policy impacts on jobs, wages, and gross state product (GSP) in Ohio.

REFERENCE CASE

The first task in developing an energy efficiency and demand response potential assessment is to determine a reference case forecast of electricity consumption, peak demand, and electricity prices in the state for a "business as usual" scenario. As with all forecasts, they are subject to significant uncertainty, particularly in times such as these when the economic outlook is a major unknown. Still, it is important to understand that while the forecast will affect the final numbers, the forecast has a very minor impact on the effectiveness of the proposed policies.

In this section we report the reference case assumptions for the analysis time period, 2009-2025. Providing an historical and prospective look at electricity consumption and demand that is agreed upon by our stakeholders is crucial to the credibility of this study. Ideally this data is provided by a state's public utilities commission. While the PUCO estimated and published their own forecast in 2008, variations in historical sales arose between the data reported by the PUCO and the data reported by the Department of Energy's Energy Information Administration (EIA). Ultimately we chose to use data from the EIA to conduct our forecast. See Appendix A for further discussion and more detailed information on the reference case assumptions.

Electricity (GWh) and Peak Demand (MW)

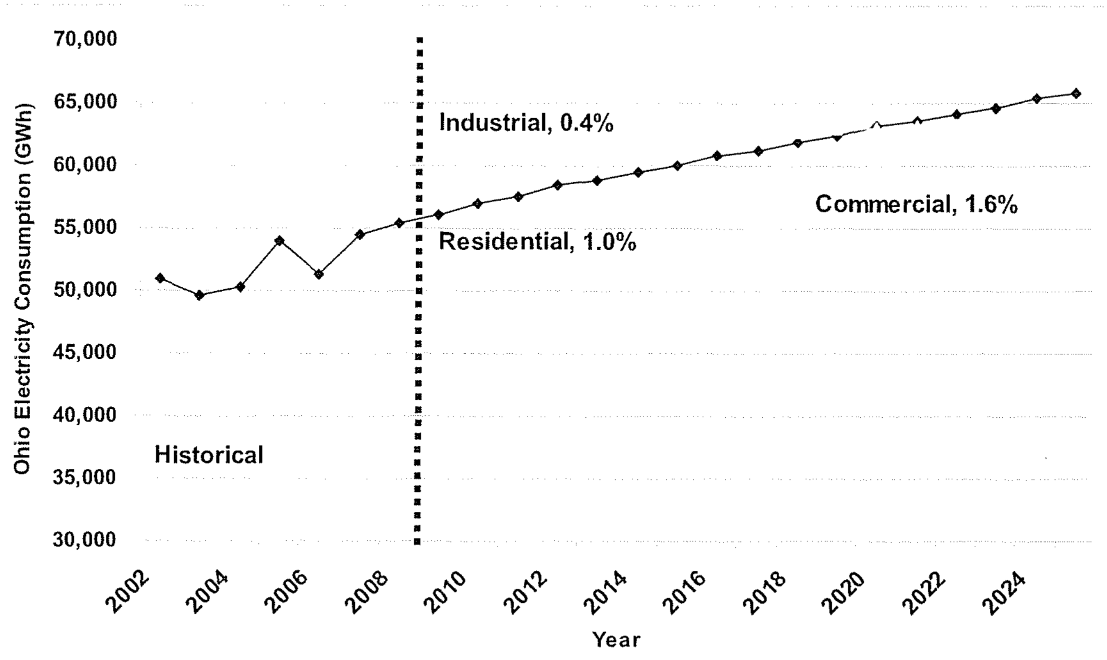
The development of the reference case for Ohio is the foundation of the quantitative analysis of the report. Our electricity consumption forecast is based on 2007 sales, the most recent year for which sales have been reported, which is then projected through 2025. For historical sales, covering 2002 through 2007, we used data from the EIA's *Electric Power Annual*, which publishes consumption data for all states individually. To estimate projected consumption, we then applied sector-specific growth rates, derived from the EIA's *Annual Energy Outlook* forecast for the East Central Area Reliability Coordination Agreement (ECARC), to actual 2007-year electric sales data. Using this methodology, we estimated total electricity consumption in the state to grow in the reference case at an average annual rate of 1.0% between 2008 and 2025, and 1.0%, 1.6%, and 0.4% in the residential, commercial, and industrial sectors, respectively (see Figure 5). Total electricity consumption in the three sectors in 2007 was 161,547 GWh and in the reference case grows to 177,954 GWh in 2015 and 193,945 GWh in 2025 (PUCO 2009).

To forecast peak demand we adjust our data from electricity sales forecast using a system load factor, which we assumed to be 60.0%. Using this methodology, we estimate peak demand growing at an average annual rate of 1.0% over the 2008-2025 period. In 2008, peak demand is expected to reach 33,705 MW increasing to 36,586 MW by 2015 and 39,770 MW in 2025 (see Figure 6).

Utility Avoided Costs

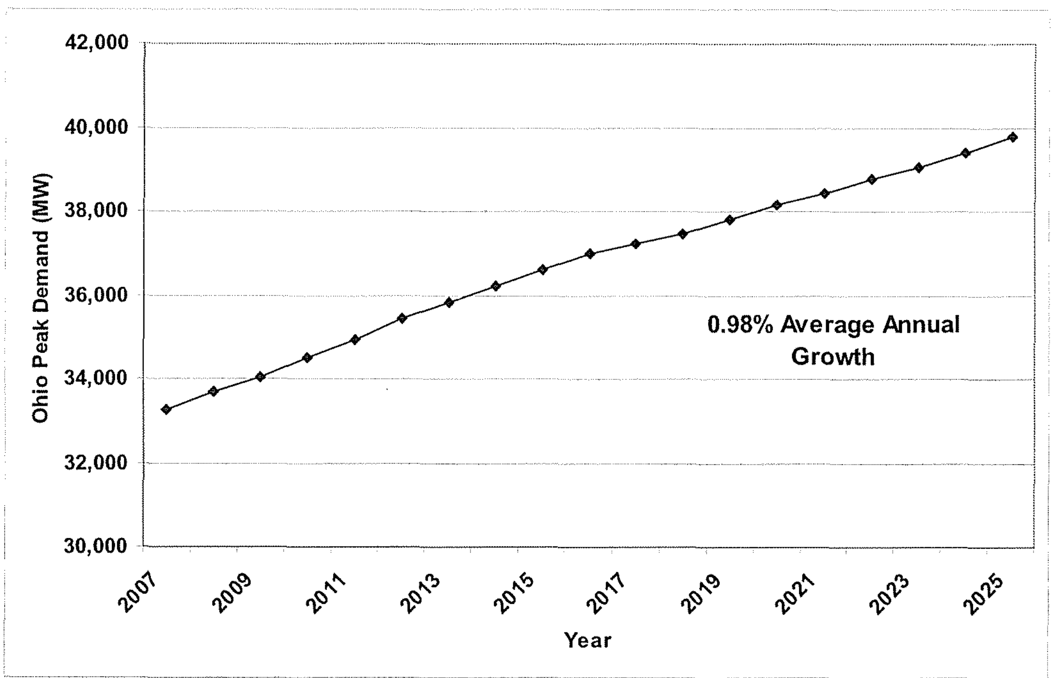
At ACEEE's request, Synapse Energy Economics developed simplified, high-level projections of utility production and avoided marginal costs. We then used these results in ACEEE's analysis to estimate the cost-effectiveness of energy efficiency measures and assess the macroeconomic impacts. The avoided cost estimates are based upon a number of simplifying and conservative assumptions. These simplifications include use of a single annual average avoided energy cost to evaluate the economics of energy efficiency measures rather than different avoided energy costs for energy efficiency measures with different load shapes. We also did not include a cost of compliance with anticipated greenhouse gas regulations. As a result, the production and avoided cost estimates should be viewed as unrealistically low. The vetting of our methodology with stakeholders revealed some concerns with the underlying assumptions. A detailed discussion of the assumptions, avoided cost estimates, and responses to these concerns can be found in Appendix A.

Figure 5. Electricity Forecast by Sector in the Reference Case, 2008-2025



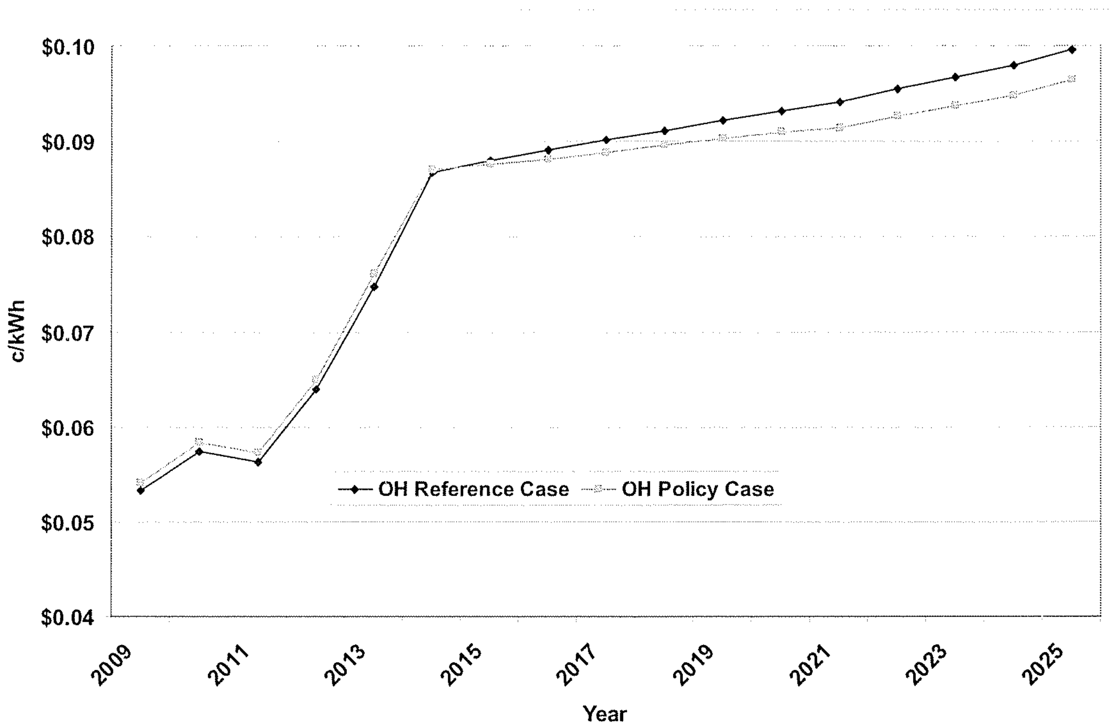
Source: EIA 2007b and 2007c

Figure 6. Ohio Peak Demand Forecast, 2008-2025



Because the level of energy efficiency and demand response measures assessed in this study significantly change the requirements of future resources, we developed two sets of production and avoided costs projections. The first case reflects the market conditions that would be anticipated in the reference case. The second case reflects the incorporation of our policy suggestions, which we discuss later. As would be anticipated, the policy case produced modestly lower avoided resource costs than the reference case, as can be seen in Figure 7. As a further conservatism in our analysis, we used this second, lower set of costs in valuing the savings that result from the analyzed policies and programs.

Figure 7. Estimates of Average Annual Avoided Resource Costs



These projections are a highly stylized representation of costs, so we suggest that a more detailed assessment of costs be undertaken as part of Ohio's energy planning process in order to reflect the locational and temporal variations across the state and throughout the year.

Retail Price Forecast

ACEEE also developed a possible scenario for retail electricity prices in the reference case. Readers should note the important caveat that ACEEE does not intend to project future electricity prices in Ohio for either the short or the long-term. Rather, our goal is to suggest a possible scenario, based on data from credible sources, and to use that scenario to estimate impacts from energy efficiency on electricity customers in Ohio.

Table 1 shows 2007 electricity prices in Ohio (EIA 2008a) and our estimates of retail rates by customer class over the study period. This price scenario is based on three key factors. First, we use the average generation cost of electricity in Ohio over the study period as calculated by Synapse Energy Economics (see above). Next, we use estimates of retail rate adders (the difference between generation costs and retail rates, which accounts for transmission and distribution costs) from the *Annual Energy Outlook* for the East Central Area Reliability Coordination Agreement (ECARC) (EIA 2007c). Finally, we estimate short-term decreases from falling generation costs due to lower prices in the cost of fuel inputs.

Table 1. Retail Electricity Price Forecast Scenario in Reference Case (cents per kWh in 2006$)

	2007*	2010	2015	2020	2025	Average
Residential	9.28	8.81	10.96	12.05	12.95	**11.01**
Commercial	8.42	8.22	9.99	11.07	12.11	**10.15**
Industrial	5.63	5.59	7.38	8.37	9.22	**7.44**
All Sector Average	7.69	7.34	9.31	10.27	11.03	**9.33**

Note: These figures are in real, 2006-year dollars and therefore do not take into account inflation.
* Actual rates (EIA 2008a), converted to 2006$

ENERGY EFFICIENCY COST-EFFECTIVE RESOURCE ASSESSMENT

In this section we present the results from our assessment of cost-effective efficiency resources in residential and commercial buildings, the industrial sector, and combined heat and power (CHP). We consider the cost-effectiveness of more-efficient technologies from the customer's perspective; i.e., a measure is deemed cost-effective if its cost of saved energy is less than the average retail rate of electricity for a given customer class. In Table 2 below we summarize the economic potential for energy efficiency by each sector in 2025. Our assessment includes only existing technologies and practices, but we anticipate that new and emerging technologies and market learning will significantly increase the cost-effective efficiency resource potential by 2025.

Table 2. Summary of Cost-Effective Energy Efficiency Potential in Ohio by Sector (2025)

Sector	Efficiency Potential (GWh)	As % of Electricity Consumption in 2025	As % of Sector Consumption in 2025
Residential	22,073	11%	34%
Commercial	17,140	9%	27%
Industrial	14,697	8%	23%
Combined Heat & Power	10,374	5%	8%*
Total	**64,284**	**33%**	

*Note: As percentage of commercial and industrial sectors combined

Residential Buildings

For our analysis of the potential for energy efficiency resources in Ohio's residential sector, we considered a scenario with widespread adoption of cost-effective energy efficiency measures during the 17-year period from 2009 to 2025. We evaluated 36 efficiency measures that might be adopted in existing and new residential homes based on their relative cost-effectiveness. An upgrade to a new measure is considered cost-effective if its levelized cost[15] of conserved energy (CCE) is less than $0.1101/kWh saved, the average retail residential electricity price in Ohio over the study time period (see Table 2). All 36 measures have a levelized cost of less than $0.1101/kWh.[16] The substantial majority (83%) of the total efficiency potential has a levelized cost of 7 cents per kWh saved or less and 53% of the measures have a cost of 4 cents per kWh or less. For the sum of all measures, we estimate a levelized cost of less than 3 cents per kWh saved (see Table 2.).[17] See Appendix C.1 for a detailed methodology and specific efficiency opportunities and cost-effectiveness for residential buildings (see Table 25).

[15] Levelized cost is a level of investment necessary each year to recover the total investment over the life of the measure.
[16] We explored additional measures, but measures above this cost-threshold were dropped from the analysis.
[17] Assuming a 5% real discount rate.

Table 2. Residential Energy Efficiency Potential and Costs by End-Use

End-Use	Savings (GWh)	Savings (%)	% of Efficiency Potential	Weighted Levelized Cost of Saved Energy ($/kWh)
HVAC	8,259	13%	37%	$ 0.029
Water Heating	2,864	4%	13%	$ 0.041
Lighting	4,774	7%	22%	$ (0.003)
Refrigeration	536	1%	2%	$ 0.058
Appliances	139	0.2%	1%	$ 0.077
Furnace Fans	1,945	3%	9%	$ 0.047
Plug Loads	1,060	2%	5%	$ 0.024
Electricity Use Feedback	1,460	2%	7%	$ 0.057
Existing Homes	21,037	32%	95%	$ 0.028
New Homes	1,036	2%	5%	$ 0.045
All Electricity	**22,073**	**34%**	**100%**	**$ 0.029**

Our analysis shows an economic potential for efficiency resources in the residential sector of 22,073 GWh over the 17-year period of 2009–2025, a potential savings of 34% of the reference case electricity consumption in 2025 (Table 2). Existing homes can reduce electricity consumption by 32% through the adoption of a variety of efficiency measures (see Appendix C, Table 26). While newly constructed homes built today can readily achieve 15% energy savings (ENERGY STAR® new homes meet this level of efficiency), we also estimate that new homes can reach 30% to 50% energy savings cost-effectively. We estimate that new residential homes can yield electricity savings of about 1,036 GWh by 2025, or 5% of total potential savings in the residential sector.

In the residential sector, improved housing shell performance (e.g., insulation measures, duct sealing and repair, reduced air infiltration, and ENERGY STAR windows) and efficient heating, ventilation, and air conditioning (HVAC) equipment and systems comprise the greatest percentage of the savings achieved through electricity efficiency resources.[18] These measures account for a total of 37% of potential savings and 13% of total electricity consumption.

Substantial savings are also attributed to improvements in lighting systems and water heating (including both more efficient water heaters as well as water-consuming appliances), which constitute 22% and 13% of residential efficiency potential, respectively (see Figure 8). Both new and existing homes in Ohio can achieve considerable energy savings by replacing household incandescent light bulbs with more efficient compact fluorescent light bulbs (CFLs).[19] Additionally, measures to reduce hot water loads (such as high-efficiency clothes washers, low-flow showerheads, and water heater jackets and pipe insulation) can yield considerable savings for households with electric water heaters. More efficient water heaters, particularly advanced technologies such as heat-pump water heaters, can further reduce electricity used for water heating.

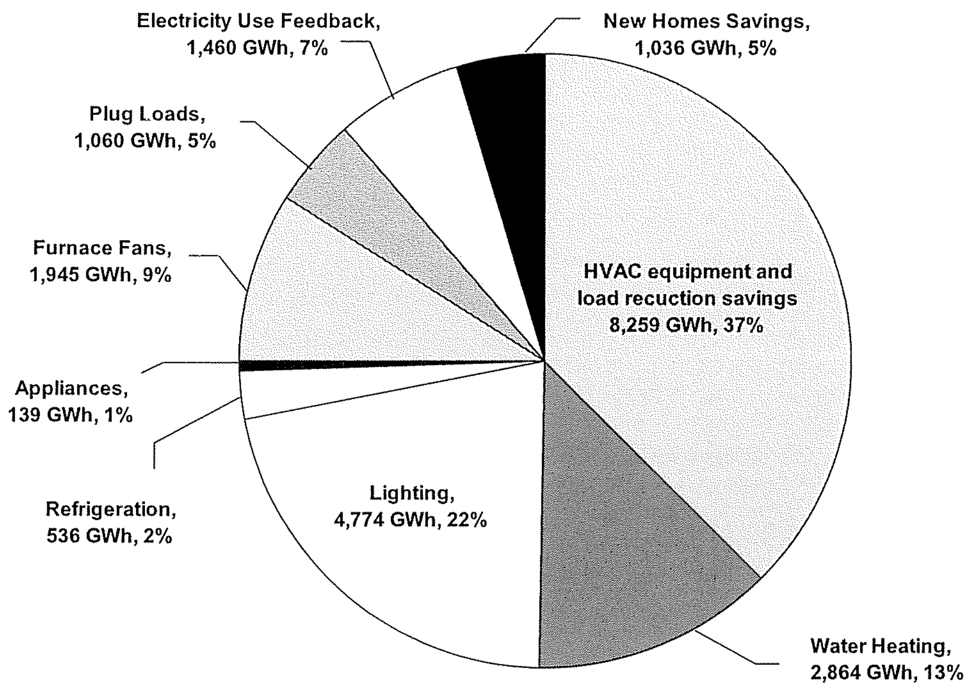
Adoption of efficient household appliances can also yield significant savings. Our analysis shows that the energy savings from replacing existing refrigerators, clothes washers, and dishwashers with units that exceed the minimum ENERGY STAR efficiency standards (Consortium for Energy Efficiency "Tier 2" in most cases), or through quality installations of these efficient models in new homes reaches 139 GWh by 2025, or 1% of total potential. Another 6% of the total savings potential can be attributed to reducing the power consumption of electronic devices that use considerable amounts of energy in standby mode. We include a measure for reducing television power consumption in active mode, which is based on ENERGY STAR Version 3.0 television specification. These measures are

[18] Savings from air-conditioners assume a baseline of 13 SEER equipment, which is the recently updated federal standard.
[19] Efficiency provisions included in the EISA 2007 will help reduce lighting loads, which decrease potential savings attributable to CFL installation. However, this does not preclude other lighting and lighting design opportunities from having an impact. LED lighting, for example, while still an emerging technology and thus not included in this study, presents another avenue for significant energy savings in the near future.

among the most cost-effective in the residential sector. The balance of potential savings comes from installing a real-time energy use feedback mechanism. Although involving a behavioral component, in-home monitors, which allow residents to track how much electricity their house is using, have been documented to result in significant and persistent savings.

Figure 8. Residential Energy Efficiency Potential in 2025 by End-Use in Ohio

Total: 22,073 GWh, 34% of Projected Electricity Consumption in 2025



Commercial Buildings

The potential for commercial electricity savings through energy efficiency in Ohio is examined through a scenario of 37 cost-effective measures for electricity savings which would be adopted during the 17-year period from 2009 to 2025. An upgrade to a new measure is considered cost-effective if its levelized cost of conserved energy (CCE) is less than $0.1015/kWh saved, which is the average retail commercial electricity price in Ohio over the study time period (Reference Price Forecast). For the sum of all measures, the estimated levelized cost is $0.016/kWh saved (see Table 4). See Appendix C.2 for a detailed methodology and specific efficiency opportunities and cost-effectiveness for commercial buildings (See Appendix C.2, Table 29).

Table 4. Commercial Electricity Efficiency Potential and Costs by End-Use

End-Use	Savings (GWh)	Savings (%)	% of Efficiency Potential	Weighted Levelized Cost of Saved Energy ($/kWh)
HVAC	3,911	6.1%	23%	$ 0.033
Water Heating	212	0.3%	1%	$ 0.033
Refrigeration	689	1.1%	4%	$ 0.017
Lighting	8,286	12.8%	48%	$ 0.011
Office Equipment	3,356	5.2%	20%	$ 0.003
Appliances and Other	30	0.0%	0%	$ 0.029
Existing Buildings	16,484	25.6%	96%	$ 0.015
New Buildings	656	1.0%	4%	$ 0.029
Total	**17,140**	**27%**	**100%**	**$ 0.016**

Commercial buildings can reduce electricity consumption by 27% through the adoption of a variety of efficiency measures. The economic potential for efficiency resources in the commercial sector, will reduce electricity use by 17,140 GWh through the period 2008-2025.

In the commercial sector, electricity savings from efficiency resources are realized through improved HVAC equipment, controls and building shell measures (e.g., roof insulation and new windows); improved water heating (e.g. heat pump water heaters); more efficient refrigeration systems (e.g. ENERGY STAR vending machines); and efficient lighting, office equipment, and miscellaneous appliances. The largest chunk of the savings, at 48%, is improved lighting efficiency. This includes more efficient light bulbs such as fluorescent and HID, as well as improved lighting controls such as daylight dimming systems and occupancy sensor.

HVAC and office equipment also provide substantial savings, at 23% and 20% respectively. HVAC measures include improved shell measures (e.g. roof insulation and improved windows), better heating and cooling systems (e.g. high efficiency chillers and heat pumps), and better controls (e.g. dual enthalpy controls and energy management system installations). Improved office equipment includes more efficient computers, printers, copiers, etc., as well as turning off this equipment after hours.

Water heating measures include heat pump water heaters, and efficient clothes washers, which reduce hot water demand. Refrigeration measures include improved commercial refrigeration systems (e.g. walk-in coolers, ice makers, vending machines).

For commercial new construction, we estimate that up to 50% savings can be reached cost-effectively.

Industry

The industrial sector is the most diverse economic sector, encompassing agriculture, mining, construction and manufacturing. Because energy use and efficiency opportunities vary by individual industry, if not individual facility, it is important to develop a disaggregated forecast of industrial electricity consumption. Unfortunately, this energy use data is not available at the state level, so ACEEE has developed a method to use state-level economic data to estimate disaggregated electricity use. This study drew upon national industry data to develop a disaggregated forecast of economic activity for the sector. We then applied energy intensities derived from industry group electricity consumption data reported and the value of shipments data to characterize each sub-sector's share of the industrial sector electricity consumption and projected the energy use through 2025. Figure 10 shows the largest electricity consuming industries in Ohio in 2008 and 2025.

Figure 9. Commercial Electricity Efficiency Potential in 2025 by End-Use in Ohio
27% of Projected Electricity Use in 2025

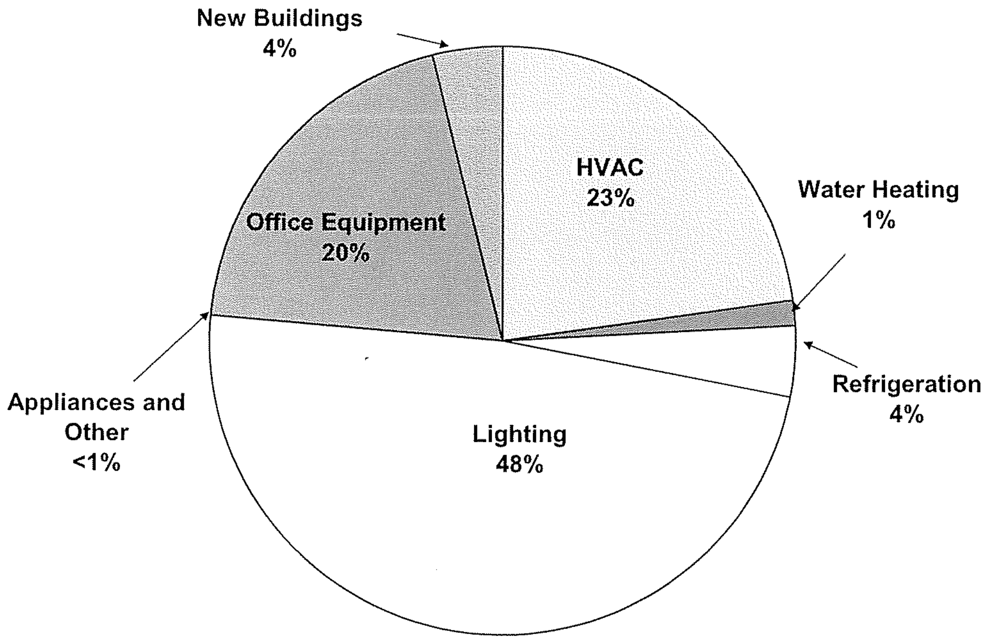
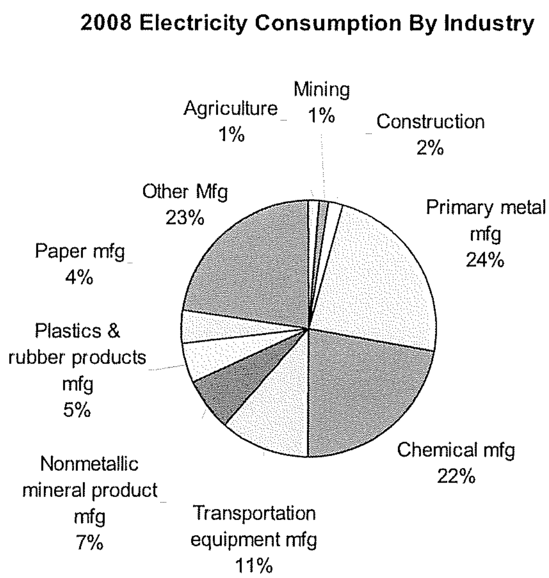
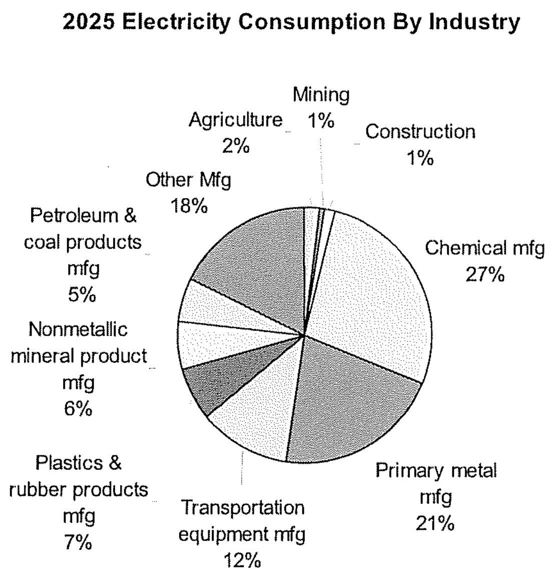


Figure 10. Estimated Electricity Consumption for the Largest Consuming Industries in Ohio in 2008 and 2025





Due to changes in economic activity and energy intensity as discussed in Appendix C, we see a significant intra-sectoral shift in electricity consumption. A small decrease in projected energy use by primary metal manufacturing coincides with a significant increase in energy use by the chemical manufacturing and plastics & rubber industries. The figure above shows their respective percentage changes in overall industrial electricity consumption. Also of note is the petroleum and coal products industry, which is projected to nearly double its energy use by 2025, and paper manufacturing, whose energy use will fall by almost half. Transportation manufacturing and machinery manufacturing will see their energy use increase by about 10% and 20%, respectively. These intra-sectoral shifts are important because they identify where new investments are being made and where energy efficiency opportunities are concentrated.

Electricity Savings

We examined 18 electricity saving measures, 10 of which were cost effective considering Ohio's 2008 average industrial electric rate of $0.0744/kWh. These measures were applied to an industry specific end-use electricity breakdown. Table 5 shows results for industrial energy efficiency potential by 2025.

Table 5. Industrial Electricity Efficiency Potential and Costs by Measure

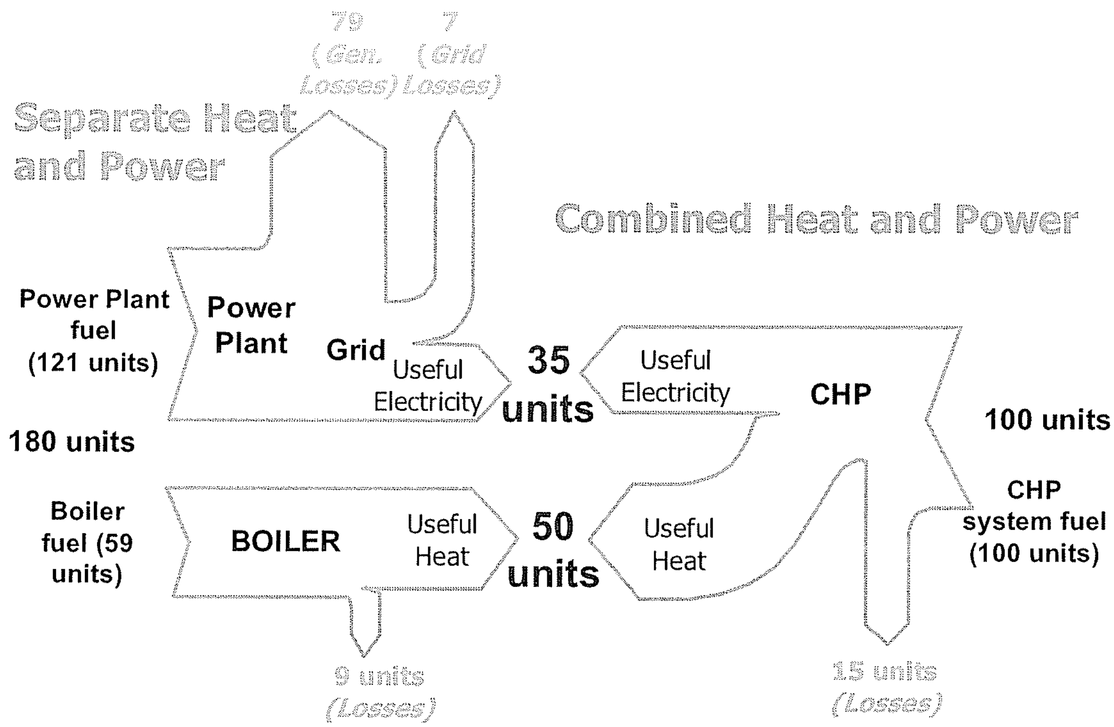
Measures	Savings Potential in 2025 (GWh)	Savings Potential in 2025 (%)	% of Efficiency Potential	Levelized Cost of Saved Energy ($/kWh)
Sensors & Controls	249	0.4%	2%	$0.014
EIS	91	0.1%	1%	$0.061
Duct/Pipe insulation	2,029	3.2%	20%	$0.052
Electric Supply	1,911	3.0%	19%	$0.010
Lighting	732	1.1%	7%	$0.020
Motors	2,352	3.7%	23%	$0.027
Compressed Air	1,015	1.6%	10%	$0.000
Pumps	1,432	2.2%	14%	$0.008
Fans	241	0.4%	2%	$0.024
Refrigeration	137	0.2%	1%	$0.003
Total	**10,191**	**16%**	**100%**	**$0.023**

This analysis found economic savings from these cross-cutting measures of 10,191 million kWh or 16% of industrial electricity use in 2025 at a levelized cost of about $0.02 per kWh saved. This analysis did not consider process-specific efficiency measures that would be applied at the individual site level because available time, funding, and data did not allow this level of analysis. However, based on experience from site assessments by the U.S. Department of Energy and other entities, we would anticipate an additional economic savings of 5–10%, primarily at large energy-intensive manufacturing facilities. The overall economic industrial efficiency resource opportunity is on the order of 21–26%. Therefore, the total economic potential for electricity savings in the industrial sector in 2025 would be about 14,967 GWh.

COMBINED HEAT AND POWER

Combined heat and power (CHP) improves efficiency by combining usable thermal energy (e.g., chilled water and steam) and power production (e.g., electricity). This co-generation process bypasses most of the thermal losses inherent in traditional thermal electricity generation, where half to two-thirds of fuel input is rejected as waste heat. By combining heat and power in a single process, CHP systems can produce fuel utilization efficiencies of 65% or greater (Elliott and Spurr 1998).

Figure 11. Schematic Comparing a Combined Heat and Power System to Separate Heat and Power Systems



For this report, Energy and Environmental Analysis (EEA), a division of ICF International, undertook an assessment of the cost-effective potential for CHP in Ohio by assessing the electricity end-uses at existing industrial, commercial, and institutional sites across the state and also considering sites that will likely be built in the future. These facilities would replace a thermal system (usually a boiler) with a CHP system that also produces power and that is primarily intended to replace purchased power that would otherwise be required at the site. EEA identified 665 MW from 45 CHP plants currently in operation. Detailed information from this analysis is provided in Appendix E.

An additional application of CHP considered by this analysis is in the production of power and cooling through the use of thermally activated technologies such as absorption refrigeration. This application has the benefit of producing electricity to satisfy onsite power requirements and displacing electrically generated cooling, which reduces demand for electricity from the grid, particularly during periods of peak demand (see Elliott and Spurr 1998).

Three levels of potential for CHP were assessed (see Appendix E for detailed results):

- *Technical Potential* represents the total capacity potential from existing and new facilities that are likely to have the appropriate physical electric and thermal load characteristics that would support a CHP system with high levels of thermal utilization during business operating hours.
- *Economic Potential* reflects the share of the technical potential capacity (and associated number of customers) that would consider the CHP investment economically acceptable according to a procedure that is described in more detail in Appendix E.
- *Cumulative Market Penetration* represents an estimate of CHP capacity that will actually enter the market between 2008 and 2025. This value discounts the economic potential to reflect non-economic screening factors and the rate that CHP is likely to actually enter the market. This potential is described in the energy efficiency policy scenarios, which are shown in the next section of the report.

The analysis identified an economic potential of around 2,600 MW of CHP capacity beyond what is already installed, assuming estimated electricity and natural gas price forecasts. In a scenario where customers installing CHP systems are given a $500 incentive per MW installed, the economic potential increases to around 4,000 MW. Policies and incentives provide an important catalyst to increasing the presence of CHP systems. In the next section, we estimate the impact that such an incentive can have on the market penetration of CHP in Ohio.

ENERGY EFFICIENCY POLICY ANALYSIS

In this section we present the suite of innovative policies and proven programs that we suggest Ohio implement in order to catalyze energy efficiency in the state.[20] We then estimate the resulting energy savings, costs, and consumer energy bill savings ($) that can be realized from their implementation. With the passing of SB 221 and the introduction of an EERS, the PUCO is now engaged in ruling how utilities will be allowed to meet the 22%+ target outlined in the EERS. Of the ten policies that we are promoting, there are five which ACEEE suggests be allowed to contribute towards the efficiency target, which have the potential to meet 10% of Ohio's electricity needs. This will leave only 12% of the EERS target to be met by the proven programs. Based on ACEEE's experience with utility programs we are confident that it is entirely feasible for them to meet and exceed 12% savings cost-effectively, however we did not attempt to quantify the degree of additional savings in this analysis.

At the end of this section we discuss the sorts of programs utilities can implement in order to satisfy the remaining 12% obligation as stipulated by the EERS. The discussion offers examples of best-practice energy efficiency programs that have proven to be successful in other states, which we take from ACEEE's report *Compendium of Champions: Chronicling Exemplary Energy Efficiency Programs from across the U.S.* (York, Kushler, and Witte 2008). In Appendix B we include a table estimating the incremental annual savings required by the EERS, which is based off of our electricity consumption forecast, and the savings that utilities will have to supplement in order to reach the percent annual EERS savings goals. The table illustrates the annual savings requirements, which are disaggregated by sector, both as a percentage as well as in GWh.

Discussion of Policies

This section provides greater detail of each of the suggested policies as well as the assumptions used in the analysis. While these policies were developed before the economic downturn, the potential for Federal stimulus funding created by the *American Recovery and Reinvestment Act* (Congress 2009) creates a unique opportunity to leverage this funding to build important human infrastructure necessary for sustained success of energy efficiency programs and policies in Ohio. The state and municipalities in the state should consider these innovative policies set forth in this section as the state prepares its plans for spending this windfall so that the Ohio will continue to benefit from this investment for years to come.[21]

Energy Efficiency Resource Standard

An Energy Efficiency Resource Standard (EERS) is a quantitative, long-term energy savings target for utilities and other entities, which is often coupled with a peak demand reduction target. Currently eighteen states, including Ohio, have adopted some form of an EERS or have established legislation directing a state agency to set an energy-savings target. This approach contrasts with many earlier state-legislated targets that were set in terms of funding levels or were relatively short term. EERS targets are typically set independently of specific program, technology, or market targets in order to

[20] The Workforce Development Initiative is not analyzed quantitatively as it is an enabling policy and does not have direct savings associated with it. Our Expanded Demand Response (DR) policy is assessed separately from the policy analysis by Summit Blue Consulting.
[21] At the time of the writing of this report, the details on conditions related to the transfer of these funds are still undecided. For current information on implementation of the federal stimulus visit: http://www.aceee.org/energy/national/fedeconomicstimulus.htm.

allow utilities maximum flexibility to find the least-cost path toward meeting the targets (Nadel et al. 2006; ACEEE 2008).

On May 1st, 2008, Governor Strickland signed SB 221, a bill created to encourage the advancement and growth of alternative energy resources, specifically renewable energy and energy efficiency. SB 221 established an EERS, which, starting in 2009, requires utilities to accumulate savings of at least 22% by 2025. The annual savings rate is set to begin at 0.3% in 2009, ramping up to 1% by 2014, followed by 1% annual savings through 2018 and 2% every year thereafter until 2025. The baseline for annual savings is the average of total kilowatt hours utilities sold during the preceding three years. The EERS is also complemented by a requirement for utilities to implement peak demand reduction programs that will save 1% in 2009, followed by 0.75% annual savings between 2010 and 2018.

The Public Utilities Commission of Ohio is currently holding rulings on what criteria should apply to the EERS as well as what policies should be allowed to contribute towards meeting the savings targets. ACEEE believes that the following criteria should apply to the EERS:

- Mandatory for Investor Owned Utilities (already included in SB 221 language)
- Voluntary commitment to lower target level by cooperatives and municipalities with some inducement
- Include incentives for exceeding savings targets, such as increased return on investment, etc.
- Require evaluation, monitoring and verification, preferably by a third-party organization

Additionally, we suggest that the following five policies – advanced residential and commercial buildings, manufacturing, rural and agricultural, and combined heat and power initiatives – be allowed to contribute towards meeting the 22%+ target. We estimate that these innovative policies will satisfy 10% of the EERS target and, along with the incentives outlined above and proven programs illustrated below, will enable utilities to surpass the 22% goal.

Advanced Residential Buildings Initiative

The development of an effective buildings program in the residential sector must focus on both new and existing homes for households of all income levels if efficiency is to be advanced on a large scale. Ohio currently has two state-sponsored residential programs in place: the Ohio *Electric Partnership Program* (EPP) and Ohio's *Home Weatherization Assistance Program* (HWAP).[22] These programs, however, focus exclusively on servicing the energy needs of low-income households. Though they have proven to be effective, we believe that there is potential to complement and broaden their scope, thus extending benefits to a larger portion of the population and, as a result, increasing the volume of electricity savings realized across the state.

Ohio's *Electric Partnership Program* (EPP) was recognized by ACEEE as one of the nation's exemplary low-income efficiency programs in our 2008 report entitled *Compendium of Champions: Chronicling Exemplary Energy Efficiency Programs from Across the U.S* (York, Kushler, and Witte 2008). EPP was designed to reduce the electric consumption of individuals in *Ohio's Percent Income Payment Plan* (PIPP) program, which assists households at or below 150% of the federal poverty level with their monthly payments (Blasnik 2006). These programs complement Ohio's *Home Weatherization Assistance Program* (HWAP), which was introduced in 1977 to provide audits and weatherization services to low-income households, as well as to improve the health, safety and overall comfort of the residents (Khawaja et al. 2006).

It is important to build upon these residential programs so that they are available to all income levels and include services beyond weatherization. Both the EPP and HWAP programs focus on weatherization assistance for low-income households in existing homes, though EPP offers equipment upgrades, such as lighting retrofits, replacement of inefficient refrigerators and freezers,

[22] More information on Ohio's residential efficiency programs is provided in the technical appendix.

and electric hot water reduction measures (Blasnik 2006) in addition to its weatherization services. An expanded weatherization initiative should redefine low-income households to include those with annual incomes up to 200% of the federal poverty level while also supporting the development of weatherization programs for existing homes for non-low-income residences.[23] Implementing energy efficiency in new construction must also be prioritized; ignoring efficiency improvements in new homes deprives Ohio of substantial energy savings and makes it more difficult to advance efficiency in the future, as these lost opportunities are more expensive and more difficult to retrofit.

The models for Ohio's residential efficiency programs should emulate ENERGY STAR's residential programs, which several states – such as New York, Vermont, and Wisconsin – have been doing for many years. For existing homes there is the Home Performance with ENERGY STAR program, which is designed as a comprehensive, whole-house approach to improving energy efficiency and comfort. The ENERGY STAR New Homes program, which is a similarly designed program that focuses on efficiency improvements during construction, can increase the efficiency of new homes 15% compared to homes built to the 2004 International Residence Code (IRC). Both programs focus not only on improving the efficiency of the home envelope, but also integrate efficient equipment, such as ENERGY STAR appliances and HVAC equipment. The incorporation of these myriad efficiency measures typically makes new homes 20-30% more efficient than standard homes.

Not all homes, new or existing, will be covered by these programs, so it is imperative that incentives are offered to households that are unable to participate. These incentives could be promoted either by utilities, or by the state through federal funding from the stimulus bill, and should establish a minimum savings of at least 20%, with greater incentives for products that generate higher savings. This sort of financial incentive, in conjunction with the advanced building initiative, also encourages contractors to purchase energy efficient appliances for new homes.

For our savings analysis of existing homes, we assume 0.5% annual savings and a participation rate (market share) of 0.5% in the first year, increasing 0.5% annually through 2016, followed by 1% annual increases through 2025. To analyze savings in new homes, we assume that new homes are able to achieve 50% savings beyond the current code, which we assume is the 2006 IECC. When the 2009 IECC becomes effective in 2011, new homes will be able to achieve 15% savings strictly from code improvements, leaving 35% still to be captured. We assume an initial participation rate of 2.5% in 2011, which doubles annually until 2014 when the 2012 IECC becomes effective. The 2012 IECC will likely deliver 30% savings beyond current code, leaving 20% savings still to be captured. Starting in 2014 we assume an annual participation rate of 20% of new homes for the remainder of the study period.[24] By the time the 2018 IECC becomes effective in 2020, which will deliver 50% savings, we assume that the program will have matured enough to allow an additional 20% savings beyond the 2018 IECC code. Under these assumptions, we estimate total savings for new and existing homes of 119 GWh in 2015 and 615 GWh in 2025, or a 0.3% reduction of total projected electricity consumption in 2025.

Advanced Commercial Buildings Initiative

Our stakeholders emphasized the necessity of a commercial buildings initiative that focuses on the ideas proposed in the Ohio Manufacturing Initiative: the need for assessments that identify energy efficiency opportunities; access to industry-specific expertise; and the need for an expansion of the trained buildings systems workforce with energy efficiency experience. Traditionally, advancing efficiency in commercial buildings was limited to efficient lighting and upgrades that focused on replacing individual pieces of equipment. While small commercial buildings will continue to reap

[23] The 2009 federal stimulus bill provides funding for low-income weatherization services as well as raises the qualification level to 200% above the poverty line.
[24] Our assumed participation rate for new homes is extremely conservative, especially for the short-term part of this analysis. For example, 57.2% of new homes in Iowa in 2006 qualified for the ENERGY STAR label, whereas 12.6% of new homes in Ohio met the ENERGY STAR standards (EPA 2007). By 2025, the ramping up of this initiative should allow Ohio to easily reach a much greater participation rate.

benefits from small-scale improvements, such as regular maintenance and individual equipment upgrades, larger commercial buildings require much broader improvements – through retrocommissioning, for example – in order to maximize energy savings.

Many retrofit programs are organized according to equipment or end-use with little emphasis on overall building performance, system optimization, or interactions among building systems. The establishment of an "Ohio Commercial Buildings Initiative" recognizes the need for programs that are tailored to address the contrasting efficiency issues between various-sized commercial buildings. A systems approach that goes beyond simple equipment upgrades to identify opportunities in system design, equipment interactions, and buildings operations and maintenance will generate greater energy savings, improve comfort, and bolster job growth through investment in training and certification for building operators, auditors, technicians, engineers, etc (Amann & Mendelsohn 2005). Again, incentives for retrofits and other commercial building upgrades could be offered by utilities, or by the state through funding allocated by the federal stimulus bill.

There are several excellent resources on how to model an effective advanced buildings program. The U.S. Department of Energy, for instance, has developed materials on how to achieve significant savings in new and existing buildings.[25] Another useful source of information is the New Buildings Institute, which has a web site on "Getting to Fifty" [percent savings].[26] ENERGY STAR also publishes a breadth of information on energy efficiency in commercial buildings and industrial plants.[27] Providing financial incentives to contractors or building owners will be crucial to guaranteeing that efficiency measures are implemented beyond what is already required by code. The Energy Policy Act of 2005 included a $1.80/square foot tax deduction for commercial building owners for each building constructed that uses 50% less than a new building designed to a national model reference code.

Combined heat and power, in conjunction with other efficiency measures, also has potential to generate significant savings in new and existing commercial buildings. H.R. 1424, titled the *Economic Stabilization Act of 2008*, includes a 10% tax credit against the cost of installing CHP systems (for the first 15MW) for systems up to 50 MW in size. Our discussions with stakeholders revealed that the health care sector – in particular hospitals and clinics, of which Ohio has well over 100 throughout the state that perpetually generate and consume considerable amounts of energy – is an excellent candidate for CHP (OHA 2008). This tax credit will provide significant impetus for the expansion of CHP systems in commercial buildings in general and help buildings in the health care sector reduce their operating costs during a time where remittances from Medicare have fallen significantly.

To estimate savings from existing buildings, we assume 1% annual savings throughout the analysis period and 1% participation rate (market share) in first year, with participation increasing by 1% annually. Savings from new construction assumes 50% savings beyond current code (IECC 2006), thereby decreasing with the adoption of new energy codes except in 2020, where we assume program implementation and participation has matured to allow for savings beyond the 50% savings from IECC 2018. In 2011 we assume an initial participation rate of 2.5%, doubling annually until 2014, when IECC 2012 becomes effective. We then assume a participation rate of 20% of new buildings for the remainder of the analysis period.[28] In 2020, when IECC 2018 becomes effective, delivering 50% savings, we assume 20% additional savings beyond IECC 2018 are achievable. Under these assumptions we estimate total savings for new and existing commercial buildings to be 133 GWh in 2015 and 715 GWh in 2025, or 0.4% of total projected electricity consumption in 2025.

[25] http://www.eere.energy.gov/buildings/highperformance/
[26] http://www.advancedbuildings.net/
[27] http://www.energystar.gov/index.cfm?c=business.bus_index
[28] Our assumed participation rate for new homes is extremely conservative, especially for the short-term part of this analysis. In other states, best practice programs for new construction in the commercial sector are achieving 50% participation rates. With time, the ramping up of this program should allow Ohio to easily meet a much greater participation rate.

Manufacturing Initiative

Based on discussions with a broad range of stakeholders involved with the manufacturing sector in Ohio, we propose a government/utility/industrial collaborative we are calling the "Ohio Efficient Manufacturing Initiative." The goal of the initiative would be to address the three key barriers to expanded industrial energy efficiency identified by the stakeholders: the need for assessments that identify energy efficiency opportunities; access to industry-specific expertise; and the need for an expansion of the trained manufacturing workforce with energy efficiency experience.

The initiative would establish Manufacturing Centers of Excellence in the model of the U.S. Department of Energy's Industrial Assessment Center (IAC)[29] program, where university engineering students are trained to conduct energy audits at industrial sites. Centers could be established at two or three main technical universities in Ohio, including The University of Dayton (UD) (the only current IAC in the state) and sites in Cleveland or Columbus. Expanding beyond the IAC model, these centers would partner with local community colleges and trade schools to bring their students into the larger network centered around the local Center of Excellence. These nearby satellite centers would extend training and associated materials to trade school and community college partners, and offer the opportunity to join the audits they conduct. Working with the Ohio Manufacturing Association and manufacturing trade associations, together with the local Manufacturing Extension Partnership (MEP) program could provide outreach to manufacturing companies that might not otherwise be aware of energy efficiency programs. Further collaboration with the Ohio Energy Office's industrial energy efficiency and sustainability programs would let the program rely on existing infrastructure and expertise on sustainability, energy, and job creation.

This initiative would provide multiple benefits to the state:

- Meet the needs of Ohio manufacturers for a trained technical workforce;
- provide valuable real-world work experience to students interested in working in manufacturing energy management;
- Meet the need of manufacturing facilities for reliable, knowledgeable, and affordable consultation with regard to their energy usage and opportunities for improved productivity; and
- Build capacity at educational facilities and in the MEP outreach efforts that connect Ohio's manufacturers to the wealth of knowledge and proficiency that resides in the state.

IAC program and implementation results recorded over the last 20 years show that this program could identify 10-20% electricity savings per facility and achieve a 50% implementation rate. Program costs for the IAC program are about $1 for every $10 saved by industry. We factor in another $0.25 per $10 saved to account for additional education costs. Under these assumptions we estimate savings of 1,721 GWh in 2015 and 5,771 GWh in 2025, or 3% of total projected electricity consumption in 2025.

We are also researching complementary policies that could leverage economic development programs to reduce Ohio's energy consumption. We also encourage the state to support an expanded federal manufacturing initiative similar to what has been suggested in recent congressional discussions.[30]

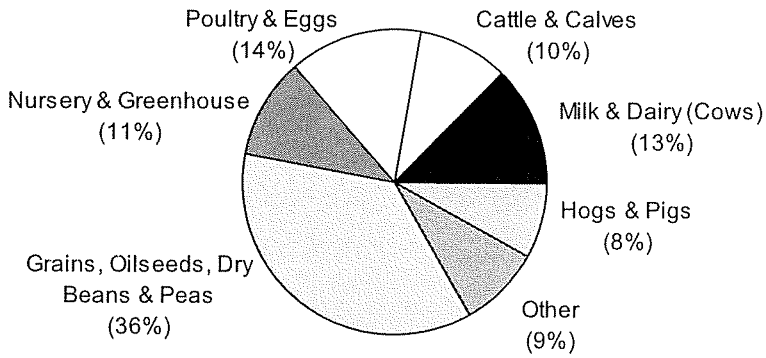
Rural and Agricultural Initiative

Agriculture makes up a little more than 1% of Ohio's industrial sector electricity use, averaging 708 GWh per year. The agricultural sector is one of the most energy-dependent sectors of our economy, relying on both direct sources of energy, such as fuels or electricity that power farm activities, or indirect energy sources such as fertilizers or other chemicals. When energy prices are unstable or increasing, farmers, ranchers and rural communities are significantly and adversely affected as

[29] For more information on the IAC program, visit: http://iac.rutgers.edu/.
[30] See http://aceee.org/industry/iac.htm.

agriculture becomes unprofitable. In 2004, electricity accounted for 21% of all energy uses on U.S. farms (Miranowski 2005). Ohio's agricultural sector produces a number of energy-intensive commodity crops, the bulk of which are grains such as soybeans, wheat and feed grains.

Figure 12. Estimated Electricity Consumption of Ohio Commodity Crops (2002)



In recent years, organizations specifically dedicated to improving efficiency on farms, ranches and rural small businesses have emerged. Existing programs are widening their focus to include agricultural energy efficiency issues and to provide more online and on-farm audits, as well as both technical and financial support. The Energy Title (IX) of the *2008 Farm Bill* provides more funding than previous legislative efforts to the Rural Energy for America Program (REAP, formerly Section 9006), which provides technical assistance and audits, as well as grants and loan guarantees for energy efficiency and renewable energy projects.[31] Although there is more money and awareness today, many states still lack the internal structure to aid their farmers, ranchers, and rural small businesses in leveraging these Farm Bill funds.[32]

The 2008 Farm Bill also authorized a new program which would provide financial assistance toward increasing the energy self-sufficiency of rural communities. The Rural Energy Self Sufficiency Initiative will fund energy assessments, help create blueprints for reducing energy use from conventional sources, and install community-based renewable energy systems.[33]

The initiatives described below are meant to build capacity within the state of Ohio in order to better provide energy efficiency-related knowledge, assessments, technical assistance and funding for rural small businesses and agricultural operations.

I. Develop an Educational Program to be administered through the Rural Electric Cooperatives, the Ohio Farm Bureau and the extension service

The Ohio Department of Agriculture, in conjunction with Ohio Department of Development, the Ohio Farm Bureau, the Ohio State Extension Service, Buckeye Power and the Ohio Rural Electric Cooperatives should establish an educational program which would disseminate information on energy efficiency best practices for farmers, ranchers and rural small businesses. This could take the

[31] Specifics on REAP project eligibility and additional information on the REAP program: http://farmenergy.org/incentives/9006faq.php#_Toc194481353.

[32] Of 1,158 applications for REAP funds in 2008, 766 were awarded grants or loan guarantees. Ohio had 12 of 22 projects awarded funds ($1,037,038). From the Environmental Law and Policy Center (ELPC)

[33] See Title VI, Energy Efficiency and Renewable Energy Programs for related program information: http://www.ers.usda.gov/FarmBill/2008/Titles/titleVIRural.htm#rural1.

form of a partnership with national organizations, such as the Rural Electricity Resource Council (RERC)[34] or the USDA-RD.[35]

There are several examples of state-specific educational programs. Southern California Edison utility runs an agriculture program that "promotes energy-efficient solutions for small and large farms, ranches, and dairies."[36] Their website provides information on a number of topics, including a *Dairy Farm Energy Efficiency Guidebook* and the Agricultural Technology Application Center (AGTAC). The latter, an "educational resource energy center," includes hands-on displays and exhibits which are open to public; demonstrations of energy-efficient technologies; educational seminars and free workshops; and provides information regarding scheduling consultations with energy experts. AGTAC "connects customers to energy-related technology solutions that are energy efficient, positive for the environment and cost competitive."[37]

In the Midwest, the Iowa Energy Center funded a project looking at the "Development of an Energy Conservation Education Program for Iowa's Livestock and Poultry Industry."[38] The work products of the study will include a curriculum, with day-long training sessions for farmers, fact-sheets and a reference manual covering energy efficiency techniques, and a training regimen for extension agricultural field specialists, to assist with the distribution of the educational materials.

Because of the regional specific nature of the agriculture sub-sector (Brown and Elliott 2003), it will be important for Ohio to tailor its programs to the unique needs of the state's agricultural industries.

II. Offer a rural audit program, building on the USDA-REAP program

Ohio utilities and extension services should make use of the reauthorized REAP program, which has $255 million dollars in mandatory funding for use over a 4-year period, to expand energy efficiency and renewable energy efforts throughout the state. ACEEE recommends that these entities provide on-site audits to farmers, ranchers and rural small businesses as a preliminary step in the REAP application process. Pinpointing areas where a farmer could save energy or implement an energy efficiency project is the first step toward identifying a successful REAP project.

Wisconsin's *Focus on Energy* program provides on-site audits with Focus energy advisors to farms and agricultural-related businesses (crop storage, grain processing, etc.). The program is marketed through multiple channels, is promoted by stakeholders including universities, extension agents, contractors, utilities and cooperatives. During the 2001-2007 period 1,500 dairy farmers participated in the program. *Focus on Energy* has promoted awareness of the Farm Bill REAP opportunities in conjunction with the Department of Agriculture and local USDA offices. Energy savings since the program began are 14.8MW, 74 kWh, and 1.4 million Therms annually (Brooks and Elliott 2007).

Alliant Energy operates a rebate and audit program for livestock and grain operations in Iowa, Minnesota and Wisconsin. The program has been in effect for more than 20 years, with over four hundred participating farms in 2006 and annual savings of 8-10 million kWh. The program also assists customers in applying for USDA funding, offering assistance for both grant application and project implementation. Specifically, the on-farm audit identifies energy waste, potential energy-efficient technologies to reduce energy usage, recommends efficient equipment specific to the

[34] RERC's web site, www.rerc.org, provides materials on energy efficiency and is a national center for information on rural electricity topics.

[35] The Ohio Dept of Development does have a Web page for the energy office and information on saving energy for industry and businesses; however, there is no agriculture or rural community-specific section. The development of that on-line resource could be one component of a future education initiative. See http://development.ohio.gov/cdd/oee/c_i_services.htm for the page in question.

[36] http://www.sce.com/b-rs/agriculture/

[37] http://www.sce.com/b-sb/energy-centers/agtac/

[38] http://www.energy.iastate.edu/Efficiency/Agricultural/cs/harmon_conserv.htm

operation, and provides information on available agricultural rebate programs. Operators can also earn cash back for purchasing recommended equipment.[39]

III. Create a pool of matching funds for USDA grants

To further promote the implementation of energy-efficient technologies and projects, Ohio should establish a system benefits charge (SBC) on electric utility bills to provide funds for matching USDA-REAP grants. Current SBC-funded programs include an advanced energy program that funds combined heat and power projects and a manufacturing facilities program that promotes advanced lighting and HVAC projects, however there are currently no such programs specifically for the agricultural sector.[40] Availability of these funds could prove vital for successful REAP applications, as the USDA is considering availability of non-REAP funding as a criterion for the application ranking process.

The New York State Energy Research and Development Authority (NYSERDA) runs the *FlexTech* program, providing cost-sharing of energy audits or feasibility studies of improvements and load management techniques that would save money on farmers' energy bills. The NYSERDA program is open to all sectors, but could be adapted in Ohio to focus exclusively on agricultural operations as a tie-in with the USDA-REAP program funding. Across all sectors, *FlexTech* realizes $5 in energy savings and $17 in implementation/construction costs for every dollar spent on feasibility studies (Brooks and Elliott 2007).

One alternative to state-run programs of the type described above would be for the state to designate a non-governmental organization to implement energy efficiency programs. Examples include Vermont's *Efficiency Vermont* organization, and the *Northwest Energy Efficiency Alliance* (NEEA) which operates in the Pacific Northwest. Additionally, there are for-profit entities such as Vermont-based *EnSave* which focus specifically on improving energy efficiency in the agricultural sector. *EnSave* works in a number of states, from Maryland to Minnesota and California, implementing programs that range from dairy efficiency and diesel emission reduction to programs that operate farm energy audits and provide rebates for implementation of on-farm energy efficiency measures.

Expanded CHP and Clean Distributed Generation

Ohio has made good strides in establishing a regulatory environment that is hospitable to the deployment of CHP and clean distributed generation (generally referred to here as "CHP"), but there is still much work to be done.

Of chief concern are the recently adopted rules guiding the development of interconnection standards applicable to distributed generation, including CHP. Ohio's Administrative Code Chapter 4901:1-22-01 delineates that ideal interconnection standards should "make compliance [with interconnection standards] not unduly burdensome or expensive for any applicant [...]" The code further requires that electric distribution utilities "establish uniform requirements for offering nondiscriminatory technology-neutral interconnection to customers who generate electricity" while considering the safety of utility workers and the environment.

The code relies heavily upon the IEEE's 1547 interconnection standard (http://grouper.ieee.org/groups/scc21/1547/1547_index.html), a widely accepted model for interconnection rules. Interconnection is separated into three tiers to allow for easier and more streamlined applications for small generators and includes a similarly streamlined application for medium-sized generators up to 2MW. A third tier provides a process for generators up to 20MW in

[39] More information on the Alliant Energy-IPL Farm Energy Audit program can be found on their web site: http://alliantenergy.com/docs/groups/public/documents/pub/p014750.hcsp.

[40] For more information visit the Ohio Department of Development web site, http://www.odod.state.oh.us/cdd/oee/ELFGrant.htm.

size. The Public Utilities Commission of Ohio provides a plain-language guide to interconnection via the new tiered system.[41]

Despite these nearly year-old requirements for new interconnection standards, research into the practices of Ohio utilities corroborated by anecdotal evidence suggests that utilities have not been quick to improve their interconnection practices in the manner required. In order to expand CHP in Ohio, the newly developed requirements for interconnection standards will need to be better implemented and enforced among the regulated utilities of the state.

Other significant regulatory treatments of CHP in Ohio include the inclusion of CHP as an eligible "alternative energy resource" within the context of the state's recently enacted *Alternative Energy Resource Standard,* part of Senate Bill 221. This is viewed as a favorable treatment of CHP. But there are other regulatory treatments of CHP that should be improved to further increase deployment. Developing output-based air emissions regulations, as promoted by the United States Environmental Protection Agency,[42] will incentivize more efficient use of fuel inputs, thus encouraging the deployment of the most efficient CHP systems. And the energy conversion property tax incentive that currently benefits the owners of some CHP systems is set to expire after the 2008 tax year. Since Ohio is currently phasing in a restructured tax code, an extension of this tax incentive may not be possible within the new tax paradigm; a continued emphasis, however, on reducing the costs of CHP systems is encouraged.

The economics of CHP have recently been assisted by the passage of the federal H.R. 1424, titled the *Economic Stabilization Act of 2008.*This act authorized the expansion of the Investment Tax Credit to include investments in CHP. It is a 10% tax credit against the cost of installing CHP systems (for the first 15MW) for systems up to 50 MW in size. While this tax credit is a boon for CHP deployment in the state, other Ohio-specific policies are not as favorable and may work to negate the positive influence on deployment that more favorable policies have. For example, current tariffs used by the largest utilities in Ohio to charge for standby electric service are counterproductive to the expanded implementation of CHP. PUCO may wish to review and address these tariffs and work to find solutions that make CHP projects more attractive to customers. The economics of CHP could also be improved through the power of the Ohio Air Quality Development Authority, which could leverage its ability to issue bonds to grant loans and other financial incentives to help companies address the high first costs of CHP systems. Since economic benefits of CHP systems accrue over time, using financing mechanisms to help spread out the costs could help business owners better integrate CHP systems into their long-term energy strategies.

Additional national incentives for CHP may be in the works. The *2007 Energy Independence and Security Act*'s Section 451 authorized additional funding and support for waste-heat recovery projects, which are an important subset of clean distributed generation. Though this authorization has not been funded, anecdotal evidence suggests it will garner attention in 2009.

Workforce Development

A key challenge stalling the achievement of the energy efficiency resource targets in SB 221 is the availability of a trained workforce. Energy efficiency tends to be more labor intensive than are supply resources, so developing a well-trained, indigenous workforce that can address efficiency issues across all market sectors is critical – a sentiment shared by the majority of stakeholders with whom we met. We thus see workforce development as a necessary element of many of the initiatives proposed above. But advancing efficiency in all sectors and throughout the entire state will require a workforce with training beyond the identification/assessment of efficiency opportunities: trained installers, technicians, engineers, architects, evaluation professionals, building operators, etc., all must be empowered with general and esoteric knowledge. Such investment in human capital will

[41] To view the guide, visit http://www.puco.ohio.gov/PUCO/Consumer/Information.cfm?id=6608
[42] For more information, visit the United States Environmental Protection Agency's CHP Partnership's informational page on output-based emissions: http://www.epa.gov/chp/state-policy/output.html

maximize the efficacy of efficiency programs while also providing additional benefit to the state's economy by creating new "green collar" jobs.

The advent of corporate and social environmental responsibility has already begun to influence the evolution of careers in building system design and operations, but identifying the needs of the market – in particular workforce needs – is and will continue to be an important facet of any initiative that aims to improve the energy efficiency of commercial and residential buildings, especially over the long term. Another key challenge will be coordinating the various programs. The establishment of an inter-agency stakeholder group to coordinate workforce development activities is therefore critical and should bring together entities such as Ohio's universities, the Ohio Board of Regents, the ODOD, and the PUCO. In New York, for example, the Building Performance Lab, housed at the City University of New York's (CUNY) Institute for Urban Systems, has established a stakeholder consortium that meets semiannually to "discuss the benefits and challenges of 'going green'" within the commercial sector. The consortium includes property owners and managers, labor representatives, utilities, city and state agencies, as well as other non-profits.[43] Since all of the initiatives we suggest within the context of the EERS policies include workforce training elements, the dynamics of the individual programs will be facilitated by a stakeholder group overseeing the process in general while providing the various parties a venue for exchanging and soliciting ideas. Communication within and between the programs is imperative to guarantee that individuals are obtaining the proper education to satisfy the needs of the individual market sectors as well as guaranteeing job placement once their training has been completed.

Ohio has already begun the process of bolstering workforce development. Universities are offering degrees and training not only through departmentally-sponsored programs, but also through joint programs with the State and Federal government. The Industrial Assessment Center at the University of Dayton (UDIAC) is one of 26 industrial assessment centers that are funded by the U.S. Department of Energy. With this funding, the UDIAC sends a small team of faculty, trained students, and professional staff to conduct free assessments for mid-sized industries, compiling reports with recommendations for reducing energy, waste and production costs.[44] UD has also joined forces with Wright State University, Central State University, and the Air Force Institute of Technology to offer the state's first masters program in clean and renewable energy, focusing on developing "a workforce for more than 45 existing Ohio companies with a stake in renewable energy and energy efficiency, as well as graduates who can start new businesses to create new Ohio jobs."[45] The program was approved by the Ohio Board of Regents in November 2008.

In July 2007, Ohio State University (OSU) created its Institute for Energy and the Environment (IEE), which brings together deans, faculty and researchers from OSU's five "hard" science colleges.[46] The IEE is not an academic unit, i.e., it does not confer degrees. But it aims to serve many other laudable purposes. As a single entity the IEE facilitates collaboration and communication amongst the five colleges, aiding in the dissemination of research at the state, national, and global level. It is also working to become a trusted resource for the state government, by acting as an intermediary between OSU experts and governmental leaders. One of its primary goals, however, is to assist OSU in advancing sustainability throughout its campus, both with regards to energy and environmental issues.

As part of one of the largest universities in the world, the IEE has the potential to become an invaluable resource. Though research at OSU focuses predominantly on supply-side efficiency issues – squeezing more Btu's out coal, solar radiation, etc. – it does have plans to expand its expertise in demand-side efficiency. The IEE is already involved in AEP's advanced metering infrastructure (AMI) program and has recently started a program called SMART@CAR, or Sustainable Mobility: Advanced

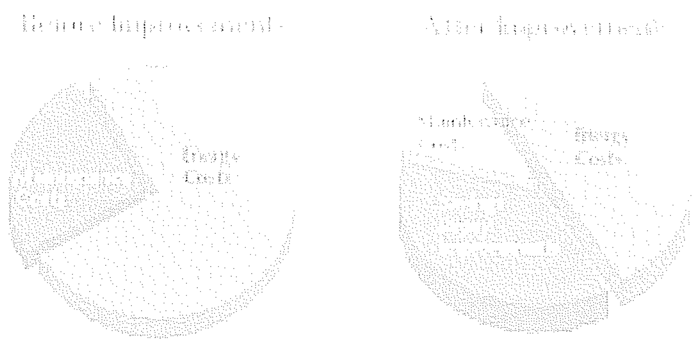
[43] For more information, please visit http://www.cunyurbansystems.org/pages/building-performance-lab.php
[44] For more information on this program, please visit: http://www.engr.udayton.edu/udiac/
[45] For more information on this program, please visit: http://www.udayton.edu/News/Article/?contentId=21494
[46] Biological Sciences; Engineering; Food, Agricultural and Environmental Sciences; Math and Physical Sciences; and Social and Behavioral Sciences.

Research Team at the Center for Automotive Research, which is a systems approach to developing the necessary infrastructure for electric vehicles. The IEE also plans to create an industrial assessment center and is cooperating with the University of Dayton in order to move forward with its project (Potter 2008).[47]

State and Local Government Facilities

State and local government facilities represent unique opportunities for Ohio to implement energy-efficient practices. Government buildings in Ohio represent almost 31% of electricity consumption in commercial buildings throughout the state (EIA 2006b)[48]. Employing energy efficiency in Ohio's government facilities serves as a model for others to follow, allowing Ohio to "lead by example." The Federal Government and a number of other states use Energy Savings Performance Contracts (ESPC) to implement energy efficiency projects at government facilities. Under the ESPC model, state agencies hire Energy Service Companies (ESCO) to implement projects designed to improve the energy efficiency and lower maintenance costs of the facility. The ESCO guarantees the performance of its services, and the energy savings are used to repay this project cost as shown in Figure 13 (KCC 2008; Birr 2008). This model has proven highly effective in many places both in terms of delivering energy savings and in terms of cost effectiveness (Hopper, Goldman, and McWilliams 2005).

Figure 13. Graphical Representation of How an ESPC Project Is Financed



Source: KCC (2008)

The key to the success of these projects is to bring together a project structure that can facilitate all aspects of the program, as is the case in Pennsylvania. Under that program, there are approximately three full-time equivalent staff supported by an experienced contractor:

1. Pre-qualifies ESCOs that can participate in the program;
2. Reviews and negotiates the terms of the ESPC agreements since the government facilities do not have the expertise to evaluate either the technical or contractual aspects of these projects; and
3. Reviews the completed projects to ensure that the projects are performing as agreed to in the contract.

Pennsylvania has been able to manage almost 50 projects each year, with total program and administrative costs of less than 2% of project costs (PA-GSA 2008; Birr 2008).

Ohio's EPSC program might be strengthened when compared to leading states such as Pennsylvania, Kansas, and Colorado, since it reaches only a portion of state facilities. A more robust structure and additional technical support might also be engaged. State agencies participate in

[47] For more information on the IEE, please visit http://iee.osu.edu/

[48] In lieu of a lack of state-specific data, we have used data for the East North Central region and assumed it is representative of Ohio.

efficiency programs, so significant additional energy efficiency opportunities still exist that could increase savings in state facilities. To address these opportunities, we recommend that Ohio expand its program, modeling the restructured program around the Pennsylvania experience drawing upon an expert consultant to complement the state agency staff (PA-GSA 2008). We also recommend that Ohio draw upon a national organization that has been formed with DOE support, the *Energy Services Coalition,*[49] which supports state and other entities in implementing ESPC programs (ESC 2008).

We also suggest that the program be extended to local government facilities. We understand that local governments can encounter bond rating problems with ESPC contracts because the rating entities may view these ESPC agreements as unsecured loans. To address this problem, the state should consider using its bonding authority, perhaps through the OAQDA, that would finance these EPSC projects, with the project funding paid back by the energy savings. The state should engage the rating entities on this issue.

In 1994, House Bill 7 was passed allowing state government agencies and universities to enter into performance contracts for energy projects. For state agencies, the authority to enter into performance contracts is vested in the Department of Administrative Services; for universities the authority is given to its Board of Trustees. The Ohio Revised Code Section 165 establishes guidelines for entering into performance contracts, requiring that:

- All contracts must be competitively solicited;
- Energy savings must exceed installation cost over a ten-year period;
- For projects involving cogeneration the maximum term is five years;
- Prevailing wage provisions apply;
- Such projects must pay for themselves out of operating funds and cannot require the use of capital budget funds; and
- Performance contracts for state agencies require the approval of the State Controlling Board.

Based on this model, we assume that state and municipal buildings in Ohio can achieve an average of 20% reduction in projected 2025 electricity sales and a 50% participation rate. We assume the average investment costs are consistent with the projected efficiency resource cost for the commercial sector identified in this report and that the program and administrative costs, which include evaluation, measurement, and verification, are 10% of the project cost. Under these assumptions, we estimate savings of 837 GWh in 2015 and 2,032 GWh in 2025, or 1% of total electricity sales in 2025.

State-Level Appliance and Equipment Efficiency Standards

Lighting and appliance standards, first authorized by Congress in the 1970s and legislated again in 1987, 1992, 2005, and 2007, have become a core energy policy for the United States, setting performance targets for dozens of common household and business products and systems. Individual states have played and continue to play an important role in advancing standards for the nation. In the 1980s, states' initiative in developing standards in the face of federal inaction led to the landmark National Appliance Energy Conservation Act of 1987 (NAECA). Since then, state enactment of product standards not covered by federal law has led to federal adoption of those same standards.

Only thirteen states have implemented standards on products that are not currently covered by federal standards introduced by the Energy Policy Act of 2005 (EPAct) and the Energy Independence and Security Act of 2007 (EISA). Estimates conducted by ACEEE show that appliance standards introduced by EPAct and EISA will save 53 and 178 TWh, respectively, by 2030, or 5% of the total projected electricity use for the U.S. While the usage and energy cost for a single device may seem small, the extra energy consumed by less efficient products collectively adds up to a significant amount of wasted energy. By implementing appliance standards on nine products not currently

[49] For more information on the Energy Services Coalition, see http://www.energyservicescoalition.org /about/index.html.

covered by federal legislation[50], Ohio could add a small, but not insignificant, amount of savings at negligible cost.

We first examine the potential savings and costs associated with the federal appliance standards promulgated by EPAct and EISA, which set standards for around 30 different products. We then estimate the additional savings that Ohio could realize should the state introduce standards on the recommended nine additional products (ASAP 2008). If Ohio were to implement its own state standards, it could realize 593 GWh of savings by 2015 and 2,003 GWh by 2025, or 1% of total electricity consumption in 2025. We estimate that federal appliance standards alone will contribute 3,071 GWh across all sectors in Ohio by 2015, increasing to 6,388 GWh by 2025. Federal and state standards together would yield savings of 3,664 GWh by 2015 and 8,390 GWh by 2025, or 4.3% of total electricity consumption in 2025. Our analysis of this scenario includes only state standards – savings from federal standards would be in addition but are not included.

Building Energy Codes

Building energy codes are a foundational policy to ensure that efficiency is integrated into all new buildings in Ohio. If efficiency is not incorporated at the time of construction, the new building stock represents a "lost opportunity" for energy savings because efficiency is difficult and expensive to install after construction is completed. Mandatory building energy codes are one way to target energy efficiency by requiring a minimum level of energy efficiency for all new residential and commercial buildings.

Ohio currently mandates compliance with ASHRAE 90.1-2004 for commercial buildings. For residential buildings, Ohio mandated compliance with the 2006 International Energy Conservation Code (IECC) code, but on March 31st, 2008, the 2006 IECC was dropped in favor of the 2003 IECC pending further investigation of the 2006 version. A specially appointed committee, the Public Hearing Draft Amendments Group 6, formed to review the 2006 IECC and recommended that, given the current economic downturn, the Ohio Board of Building Standards (OBBS) allow for an Ohio-specific prescriptive path that offers another, less stringent method of compliance in hopes of minimizing the financial burden on Ohio's home contractors and buyers. The OBBS convened November 7th, 2008, to hear public comments on the proposed re-adoption of the 2006 IECC and the additional prescriptive path (BCAP 2008). On December 12th, 2008, the OBBS passed Amendments Group 6, which effectively relaxed code standards on new residential construction.

A closer look at the changes recommended by the Public Hearing Draft Amendments Group 6 shows that they are counterproductive to advancing energy efficiency in Ohio. The proposed changes decrease the stringency of the state code and, consequently, could lead to a significant loss of energy efficiency statewide as well as greater energy costs for home owners. Home builders will be able to comply with the state code by following one of three paths: the 2006 IECC, the 2006 IRC, and the state-specific prescriptive path. These paths have distinctly different efficiency requirements – the 2006 IECC being the most stringent – and collectively have the potential to reduce energy efficiency in new homes significantly. Code officials will be trained to the Ohio-prescriptive path, further reducing the incentive to build homes that are energy efficient.

The implementation of the changes in Amendments Group 6 will also make it more difficult for utilities to meet the savings targets promulgated in SB 221. Allowing home builders to follow a state-specific prescriptive path, which allows equipment "trade-offs" for homes with a window-to-wall area of less than 23%, is an option that is prohibited by the 2009 IECC and one that makes Ohio unique. For example, contractors will essentially be able to trade-off a more efficient furnace instead of making improvements to the thermal envelope, such as windows or insulation. However, many utilities offer incentives for the purchase and installation of efficient furnaces as a means of decreasing energy consumption. Allowing contractors to exchange an efficient furnace for thicker insulation encourages

[50] These products include furnace fans, compact audio equipment, DVD players and recorders, portable electric spas (hot tubs), water dispensers, hot food holding cabinets, televisions, and portable light fixtures.

them to downgrade the home envelope for efficiency improvements that they are already installing. Substituting efficient HVAC equipment for an efficient home envelope will hurt energy efficiency over the life of the home because HVAC equipment typically has a lifetime half as long as envelope measures. And home owners will not necessarily replace their furnace with an equally efficient product, while a less-efficient thermal envelope will be difficult, and costly, to upgrade in the future. The availability of this trade-off could completely offset the level of energy savings that utilities can realize through furnace-incentive programs (MEEA 2008 and Misuriello 2008).

Additionally, the changes in Amendments Group 6 will redraw the climate zones created by the Department of Energy, relocating 30% of Ohio's population into a zone whose energy efficiency requirements are less stringent. Currently only nine counties reside in climate zone 5, which has less-stringent efficiency requirements. The changes in Amendments Group 6 will move an additional twenty-seven counties from climate zone 4 into climate zone 5.

Installing energy efficient products increases costs marginally, but improves the marketability of a new home by increasing comfort and minimizing energy bills through reduced consumption. While the economic concerns of Ohio's home builders should not be ignored, we believe it is imperative that Ohio's prescriptive path remain effective only temporarily. Furthermore, Ohio should be diligent about updating its energy codes by implementing new versions of the IECC as they become available. Our policy analysis reflects this ideal commitment: we assume that the 2006 IECC is the baseline efficiency standard and that Ohio will adopt the 2009 IECC, effective 2011, followed by the 2012 IECC, effective 2014, and the 2018 IECC, effective 2020. We assume enforcement of each codes starts at 70% compliance in the first year, 80% in the second year, and 90% in the third and subsequent years.[51] Given these assumptions, we estimate that savings from energy codes will reach 343 GWh by 2015 and 1707 GWh by 2025, or 0.9% of total electricity consumption in 2025.

Discussion of Proven Utility Programs

We have illustrated that the innovative policies suggested above have the potential to generate 10% of the required 22% electricity savings by 2025, giving utilities a substantial boost towards meeting the EERS target. Based on the results from our policy analysis, we estimate that these programs will only have to meet the remaining 12%, or 20,596 GWh, of the 22% EERS target. Our economic potential analysis for the residential and commercial sectors show that they account for 56% and 44% GWh, respectively, of the 39,213 GWh in total savings we estimate for those two sectors in 2025. We assume that this same ratio will apply to the relative contribution of the two sectors from future utility-run programs, which amounts to 11,594 and 9,003 GWh for the residential and commercial sectors, respectively.

There are many examples of program designs that have proven successful over the past three decades. In the text box below, we present several of these program types along with specific examples of successful implementations that are drawn from ACEEE's report *Compendium of Champions: Chronicling Exemplary Energy Efficiency Programs from across the U.S.* (York, Kushler, and Witte 2008).

Examples of Proven Energy Efficiency Programs

- ***Commercial/Industrial Lighting Programs***: Provide recommendations and incentives to businesses to increase lighting efficiency. Aiming to expedite the adoption of new technologies and decrease end-user's energy costs, the programs focus on marketing the most advanced lighting products and encourage greater efficiency in system design and

[51] It is important to note that adopting the most recent energy codes will require a concomitant effort to enforce their implementation. Statewide verification of compliance rates is critical in determining the efficacy of energy codes in reducing electricity demand.

layout. Xcel Energy's *Lighting Efficiency* program reached 4,346 participants, saving a total of 273 GWh during the years 2002-2006.

- ***Commercial/Industrial Motor and HVAC Replacement Programs*:** Encourage the marketing and adoption of higher efficiency motors and HVAC equipment by offering rebates to distributors and end-users of qualifying equipment. Through monetary incentives and energy efficiency education, program advocates are shifting market tendencies away from a focus on initial equipment cost and toward an environment where lifecycle cost is increasingly considered by consumers. During 2006, Pacific Gas & Electric's *Motor and HVAC Distributor Program* saved a total of 16.55 GWh of electricity by offering $3.9 million in rebates.

- ***Commercial/Industrial New Construction Programs:*** Focus on training, educating, and providing financial incentives for architects, engineers, and building consultants to implement energy saving measures and technologies. By offering both prescribed and customizable incentive packages, these programs are able to influence a wide range of projects, which have in turn had the effect of raising the standards for energy efficiency in normal building practices. With its four distinct, yet combinable project "tracks," Energy Trust of Oregon, Inc.'s *Business Energy Solutions: New Buildings* program offers qualifying projects incentives of up to $465,000 each, which saved approximately 46.8 GWh of electricity and 1.2 million therms of natural gas through the end of 2007.

- ***Commercial/Industrial Retrofit Programs:*** With programs ranging from energy efficiency audits to financial assistance to even providing detailed engineering installation plans, Commercial/Industrial Retrofit Programs are designed to help implement cost-effective energy efficiency measures during new construction, expansion, renovation, and retrofit projects in commercial buildings. Programs focus on long-term energy management, peak load reduction, load management, technical analysis, and implementation assistance in order to give building owners and operators a better understanding of the energy related costs of, and potential savings for, their commercial buildings. Rocky Mountain Power and Pacific Power created approximately 100 GWh of gross electricity savings in Washington and Utah with their *Energy FinAnswer and FinAnswer Express* programs.

- ***Residential Lighting and Appliances:*** Headed by utility companies and energy nonprofits alike, Residential Lighting and Appliances Programs advocate the adoption of ENERGY STAR light bulbs, light fixtures, and home appliances through the use of rebates, marketing campaigns, advertising, community outreach, and retailer education. Lighting programs have focused on establishing and maintaining a customer base for compact fluorescent bulbs, in addition to fostering relationships between manufacturers and retailers in order to lower costs to the consumer. Appliance programs have sought to educate consumers on the long-term benefits of replacing aging, inefficient refrigerators, freezers, air conditioning units, and other large appliances with ENERGY STAR models, while providing an incentive to upgrade older models through rebates offered both for recycling old units and purchasing new ones. By selling 1.3 million CFLs during 2006 through its *ENERGY STAR Residential Lighting Program*, Arizona Public Service anticipates saving a total of 360 GWh of electricity during the lifetime of the light bulbs. Additionally, the *California Statewide Appliance Recycling Program* recycled 46,829 aging appliance units in 2007, a measure that saved 33.3 GWh of electricity in 2006.

- ***Residential Mechanical Systems Programs:*** Provide rebates and other financial incentives to contractors trained to properly install and service high-efficiency air conditioning, heat pumps, and geothermal heat-pump technologies. In addition to encouraging the purchase of energy-efficient appliances, these programs help to verify that existing equipment is appropriately installed and tuned in accordance with manufacturers' specifications, in order to optimize energy savings. Long Island Power Authority's *Cool Homes* Program has helped to introduce approximately 40,000 high-efficiency central cooling systems into the market, creating 29 GWh of annual electricity savings in 2006.

- ***Residential New Homes Programs:*** Provide incentives to builders who construct energy-efficient homes that achieve long-term, cost-effective energy savings. By addressing efficiency during the construction of homes and apartments, builders are able to maximize the financial and environmental benefits of efficient insulation, windows, air ducts, and appliances. Furthermore, ENERGY STAR certification provides developers with additional marketing strategies to attract buyers and renters. Some Residential New Homes programs also offer assistance to builders in developing efficiency objectives, and to potential buyers in locating efficient homes. With 100 participating residential builders and over 2,300 homes built to date, Rocky Mountain Power's *ENERGY STAR New Homes Program* saved 3.4 GWh of electricity during 2006.

- ***Residential Retrofit Programs:*** With an emphasis on large scale systematic retrofits, Residential Retrofit Programs are designed to reduce electric and natural gas consumption and peak-time demand of residential buildings. Financial incentives, low-interest financing, and training are offered to residents and customers interested in assessing and improving their energy efficiency. From weatherization and duct sealing to installation of new technologies, proponents of Residential Retrofit Programs direct their efforts both to buildings with the highest energy usage and constituents with the greatest financial need. Since its inception in 1993, Vermont Gas Systems, Inc.'s *HomeBase Retrofit Program* has installed over 1,600 kWh in energy saving measures, contributing to over 77,000 Mcf of natural gas savings.

- ***Low-Income Programs:*** Seek to educate and assist qualifying participants in acquiring appropriate home weatherization, energy-efficient lighting and appliances, and other efficiency improvements. By helping limited income households increase their energy efficiency and reduce energy consumption, these programs in turn minimize long-term energy costs to customers. Through its *Appliance Management Program and Low-Income Services*, National Grid has reached over 40,000 customers, creating 42 GWh of annual energy savings.

Energy Efficiency Policy Scenario Results

This section describes results from our policy analysis, including estimated electricity savings and peak demand impacts from efficiency in 2015 and 2025. More detailed results are shown in Appendix B. The demand response potential and impacts on peak demand are covered in the next section and in Appendix D.

Table 6. Summary of Electricity Savings by Policy or Program

	Annual Electricity Savings by Policy (GWh)	2015	2025	Total Savings in 2025 (%)*
	Innovative Programs & Policies			
1	Efficient Homes Initiative	119	615	0.4%
2	State-level Appliance Standards	593	2,003	1.3%
3	Building Energy Codes	343	1,707	1.1%
4	Commercial Buildings Initiative	133	715	0.5%
5	State Facilities	837	2,032	1.3%
6	CHP	1,072	3,238	2.1%
7	Manufacturing Initiative	1,721	5,771	3.7%
8	Rural and Ag. Initiative	57	155	0.1%
	Innovative Program & Policy Savings	**4,876**	**16,235**	**10.3%**
9	*Proven Utility Programs*			
	Residential	2,078	11,328	7.2%
	Commercial	1,701	9,268	5.9%
	Proven Utility Program Savings	**3,779**	**20,596**	13.1%
	Total Savings (Policy + Program)	**8,655**	**36,831**	**23.4%**
	Adjusted Electricity Forecast (GWh)	**169,299**	**157,114**	
	Savings (% Reduction in Reference Case)	**4.9%**	**19.0%**	

Notes

* Percent relative to adjusted reference case forecast

1 Initiative broken down into programs for existing homes and new construction. Existing homes program assumes 0.5% savings throughout the analysis period and 1% participation rate in first year, with participation increasing by 1% annually. Savings from new construction assumes 50% savings beyond current code (IECC 2006), thereby decreasing with the adoption of new energy codes except in 2020, where we assume program implementation and participation has matured to allow for savings beyond the 50% savings from IECC 2018. In 2011 we assume an initial participation rate of 2.5%, doubling annually until 2014, when IECC 2012 becomes effective. We then assume a participation of 20% for the remainder of the analysis period. In 2020, when IECC 2018 becomes effective, delivering 50% savings, we assume 20% additional savings beyond IECC 2018 are achievable

2 Appliance and equipment efficiency standards were adopted at the federal level in the 2007 energy bill, which also directed DOE to set standards for additional products in the coming years. This Scenario assumes savings from these standards, which are not taken into account in the reference case load forecast. Savings and cost assumptions are from a forthcoming ACEEE and ASAP standards analysis.

3 We assume IECC 2009 is adopted, which goes into effect 2011, the IECC 2012 is adopted and goes into effect in 2014, and the IECC 2018, effective 2020. We estimate that these codes achieve a 15%, 30%, and 50% energy savings improvement beyond IECC 2006 requirements, respectively. Savings apply only to end-uses covered under building codes, which are HVAC, lighting, and water heating end-uses, or 50% of electricity consumption in new residential construction and nearly 60% of electricity consumption in commercial buildings. We assume enforcement of each code starts at 70% compliance in the first year, 80% in second year, and 90% in the third and subsequent years. Buildings analysis shows $0.47 per kWh investment cost for new ENERGY STAR homes, which achieve 15% savings, and $0.32 per kWh for new commercial buildings meeting 15% and 30% beyond code. We assume $1.5 million dollars per year to implement and enforce codes, based on recommendations in New York (NY DPS 2007). This is similar to estimates in VA that new program costs run 2-3% of building costs.

4 Initiative broken down into programs for existing buildings and new construction. Existing buildings program assumes 1% savings throughout the analysis period and 1% participation rate in first year, with participation increasing by 1% annually. We assume that 68.5% of total commercial electric floorspace is non-governmental buildings, to avoid double-counting savings attributable to state facilities program (CBECS 2003, table C17). Savings from new construction assumes 50% savings beyond current code (IECC 2006), thereby decreasing with the adoption of new energy codes except in 2020, where we assume program implementation and participation has matured to allow for savings beyond the 50% savings from IECC 2018. In 2011 we assume an initial participation rate of 2.5%, doubling annually until 2014, when IECC 2012 becomes effective. We then assume a participation of 20% for the remainder of the analysis period. In 2020, when IECC 2018 becomes effective, delivering 50% savings, we assume 20% additional savings beyond IECC 2018 are achievable.

5 We estimate 31.5% of total electric commercial floorspace is government buildings, from EIA (CBECS 2003, table C17). We then assume a savings rate of 20% and a participation rate of 50% over the period of the analysis.

6 We assume a $500 incentive per MW for CHP facilities.

7 This scenario assumes that the number of industrial assessments ramps up from 50 to 200 in first three years, that each assessment identifies 15% electricity savings, and that 50% of identified savings are implemented. Project costs assume the average investment cost per kWh from the industrial sector analysis ($0.28/kWh) and program cost is assumed to be 12.5% of projected cost savings to the end-user.

8 Based on similar programs and values from the State of Wisconsin Focus on Energy 2007 Semiannual Report, we assume the average cost of conserved energy at $0.025/kWh, that program & administrative costs are 24% of the cost of investment, and that customers cover half of the investment cost.

9 Savings for proven programs are the difference between EERS requirements and policy savings. Sector savings are then allocated based on the contribution to economic potential savings of the residential and commercial sectors.

Table 7. Summary of Summer Peak Demand Reductions by Sector (MW)

Sector	2015	2025	Total Savings in 2025 (%)
Residential	637	3,801	10%
Commercial	328	1,121	3%
Industrial	585	2,159	5%
Total Savings (MW)	**1,550**	**7,081**	**18%**
% Reduction (relative to forecast)	**4%**	**18%**	

Cost and Benefits from Policy Analysis

In this section we estimate the costs and benefits of our energy efficiency policy analysis to determine overall cost-effectiveness. There is no single answer to whether energy efficiency is cost-effective, but rather there are multiple perspectives analysts utilize to determine cost-effectiveness. Here, we examine our policy analysis using two cost-effectiveness tests: the Total Resource Cost (TRC) test and the Participant Cost test. We do not do an equivalent analysis for the demand response policy scenario, which is discussed in the next section, due to the difficulty in evaluating the dollar savings benefits to consumers from demand response measures.

The costs needed to run the efficiency policies suggested in our policy analysis and to achieve the estimated electricity savings include both the investments in efficient technologies or measures and the administrative or marketing costs to run programs and administer policies. The technology investments might include any combination of incentives paid to customers or direct consumer costs. See Table 8 for a breakdown of the estimated costs of the policies from our analysis. See Appendix B for estimates of Total Resource Costs.

Table 8. Annual Energy Efficiency Costs from Policy Analysis (Millions of 2006$)

	2015	2025
Customer Investments	$ 380	$ 823
Incentives Paid to Customers	$ 126	$ 390
Admin/Marketing Costs	$ 28	$ 99
Total Costs	**$ 533**	**$ 1,312**

Note: These costs are undiscounted and shown in real 2006$

The chapter on macroeconomic impacts uses these cost assumptions to estimate impacts of the efficiency policies on the economy, including overall benefits to customers. Here, we report a net present value (NPV) analysis of costs and benefits to society and to participants. The next two tables (see Table 9 and 10) show results from the TRC test and the Participant Cost test, respectively, with a breakdown of total costs and benefits (present value in 2006$) by policy type and by sector over the study time period (2008–2025). Readers should note that although the study time period ends in 2025, savings from the efficiency measures persist over the lifetime of each specific measure. Accounting for these additional savings beyond the study time period would yield additional benefits and therefore a higher benefit/cost ratio.

The TRC test, as shown in Table 9, evaluates the net benefits of energy efficiency to the region as a whole. This test considers total costs, including investments in efficiency measures (whether incurred by customers or through incentives) and administrative or marketing costs. Benefits in the TRC test are the avoided costs of energy, or the marginal generation costs that utilities avoid by reducing electricity consumption through energy efficiency. The avoided energy resource costs were determined by the analysis by Synapse Energy Economics (see Appendix A). The TRC test, which shows an overall benefit-to-cost ratio of 1.7, suggests a net positive benefit to Ohio as a whole from implementing these efficiency programs and policies. Accounting for additional savings beyond the study time period would yield a benefit/cost ratio of 2.9.

See Figure 14 for a representation of the results using three different discount rates.

Table 9. Total Resource Cost (TRC) Test (2008-2025) (Millions of 2006$)

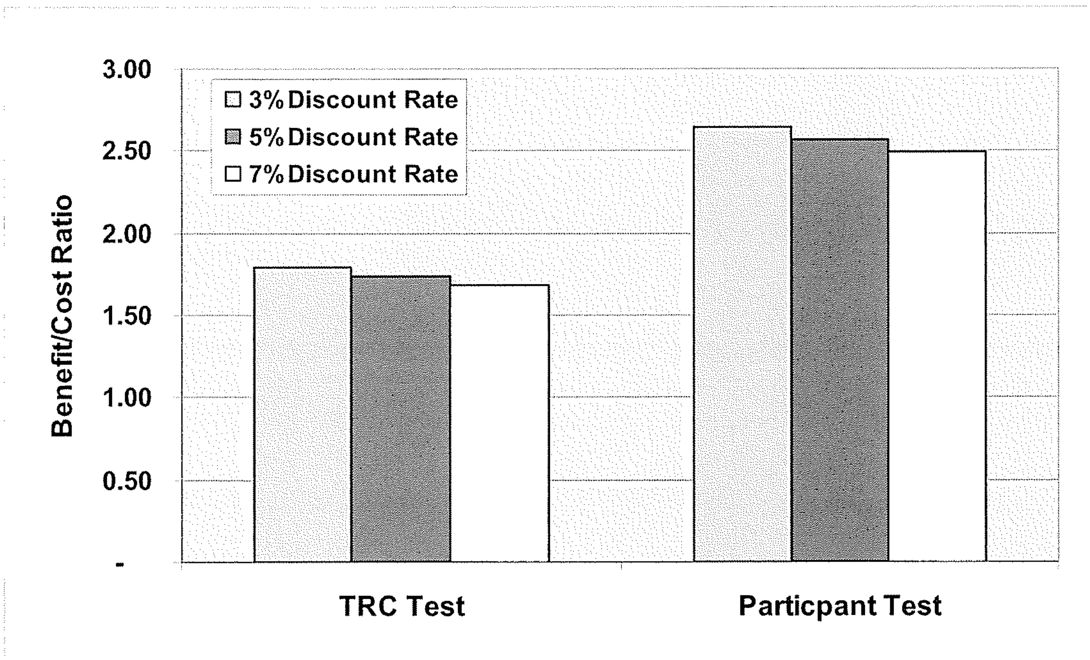
By Policy/Program	**NPV Costs**	**NPV Benefits**	**Net Benefit**	**B/C Ratio**
Innovative Programs & Policies				
Efficient Homes Initiative	$ 164	$ 194	$ 29	1.2
State-level Appliance Standards	$ 566	$ 795	$ 229	1.4
Building Energy Codes	$ 439	$ 541	$ 102	1.2
Commercial Buildings Initiative	$ 195	$ 220	$ 25	1.1
State Facilities	$ 253	$ 926	$ 673	3.7
CHP	$ 1,232	$ 1,340	$ 109	1.1
Manufacturing Initiative	$ 1,016	$ 2,200	$ 1,184	2.2
Rural and Ag. Initiative	$ 3	$ 66	$ 63	21.3
Proven Utility Programs				
Residential	$ 2,250	$ 3,436	$ 1,186	1.5
Commercial	$ 1,095	$ 2,811	$ 1,716	2.6
Total	**$ 7,214**	**$ 12,528**	**$ 5,314**	**1.7**
By Sector	**NPV Costs**	**NPV Benefits**	**Net Benefit**	**B/C Ratio**
Residential	$ 3,196	$ 4,733	$ 1,537	1.5
Commercial	$ 2,377	$ 4,862	$ 2,485	2.0
Industrial	$ 1,642	$ 2,934	$ 1,292	1.8
Total	**$ 7,214**	**$ 12,528**	**$ 5,314**	**1.7**

The Participant Cost test, as shown in Table 10, takes the perspective of a customer installing an energy efficiency measure in order to determine whether the participant benefits. The costs are the costs to customers for purchasing or installing energy efficiency and the benefits are the savings on customers' electricity bills due to reduced consumption plus any incentives paid to the customers. Again, this analysis only takes into account costs and benefits through 2025, even though customer savings on electric bills would continue well past 2025. Without accounting for the benefits that persist after measures installed in 2025, the Participant Cost test yields a positive benefit to participants, with a benefit/cost ratio of 1.9. Accounting for additional savings beyond the study time period would yield a benefit/cost ratio of 4.0.

Table 10. Participant Cost Test (2008-2025) (Millions of 2006$)

By Policy/Program	**NPV Costs**	**NPV Benefits**	**Net Benefit**	**B/C Ratio**
Innovative Programs & Policies				
Efficient Homes Initiative	$ 131	$ 309	$ 178	2.4
State-level Appliance Standards	$ 564	$ 1,056	$ 491	1.9
Building Energy Codes	$ 425	$ 711	$ 286	1.7
Commercial Buildings Initiative	$ 156	$ 332	$ 176	2.1
State Facilities	$ 230	$ 1,156	$ 926	5.0
CHP	$ 1,232	$ 1,881	$ 649	1.5
Manufacturing Initiative	$ 978	$ 2,060	$ 1,081	2.1
Rural and Ag. Initiative	$ 2	$ 63	$ 61	25.2
Proven Utility Programs				
Residential	$ 2,000	$ 5,643	$ 3,643	2.8
Commercial	$ 996	$ 4,014	$ 3,019	4.0
Total	**$ 6,715**	**$ 17,225**	**$ 10,510**	**2.6**
By Sector	**NPV Costs**	**NPV Benefits**	**Net Benefit**	**B/C Ratio**
Residential	$ 2,905	$ 7,432	$ 4,527	2.6
Commercial	$ 2,207	$ 6,833	$ 4,626	3.1
Industrial	$ 1,603	$ 2,960	$ 1,357	1.8
Total	**$ 6,715**	**$ 17,225**	**$ 10,510**	**2.6**

Figure 14. Results of TRC and Participant Cost Tests Using Three Discount Rates



Assessment of Demand Response Potential

This section defines Demand Response (DR), assesses current DR activities in Ohio, uses benchmark information to assess DR potential in Ohio, and concludes with policy recommendations that could foster DR contributing appropriately to the resource mix in Ohio that can be used to meet electricity needs. Potential load reductions from DR are estimated for set of DR programs that represent the technologies and customer types that span a range of DR efforts.

Defining Demand Response

DR focuses on shifting energy from peak periods to off-peak periods and clipping peak demands on days with the highest demands. Within the set of demand-side options, DR focuses on clipping peak demands that may allow for the deferral of new capacity additions and enhance operating reserves to mitigate system emergencies. Energy efficiency focuses on reducing overall energy consumption with attendant permanent reductions in peak demand growth. Taken together, these two demand-side options can provide opportunities to more efficiently manage growth, provide customers with increased options to manage energy costs, and develop least cost resource plans.

DR resources are usually grouped into two types: 1) load-curtailment activities where utilities can "call" for load reductions; and 2) price-based incentives which use time-differentiated and/or dispatchable rates to shift load away from peak demand periods and reduce overall peak-period consumption. Interest in both types of DR activities has increased across the country as fuel input prices have increased, environmental compliance costs have become more uncertain, and the substantial investment in overall electric infrastructure needed to support new generation resources.

The summary of DR potential presented on Table 1 focuses on load-curtailment and backup generation and does not include savings resulting from price-based incentives. Residential load-curtailment typically involves direct load control (DLC) of air conditioners—although this can also cover appliances—as well as temperature offsets, which increase thermostat settings for a certain period of time. Commercial and industrial applications of DR focus on load control of space conditioning equipment, however this depends on customer size: self-activated load reductions are usually more prudent for larger customers. Backup generation for commercial and industrial applications involves generators with start-up equipment that allows them to come online with short notice from utilities, relieving the additional demand on the system during peak hours.

Rationale for Investigating Demand Response

DR alternatives can be implemented to help ensure that a utility continues to provide reliable electric service at the least cost to its customers. Specific drivers often cited for DR include the following:

- **Ensure reliability** – DR provides load reductions on the customer side of the meter that can help alleviate system emergencies and help create a robust resource portfolio of both demand-side and supply-side resources that meet reliability objectives.
- **Reduce supply costs** – DR may be less expensive per megawatt than other resource alternatives.
- **Manage operational and economic risk through portfolio diversification** – DR capability is a resource that can diversify peaking capabilities. This creates an alternative means of meeting peak demand and reduces the risk that utilities will suffer financially due to transmission constraints, fuel supply disruptions, or increases in fuel costs.
- **Provide customers with greater control over electric bills –** DR programs would allow customers to save on their electric bills by shifting their consumption away from higher cost hours and/or responding to DR events.
- **Address legislative/regulatory interest in DR –** Recent legislation, Ohio House Bill 2200, calls for peak load reduction, smart meter deployment, and the availability of time-based rates for all customers.

Background of Demand Response in Ohio

A sound strategy for development of DR resources requires an understanding of Ohio's demand and resource supply situation, including projected system demand, peak-day load shapes, and existing and planned generation resources and costs.

Ohio utilities serves a population of over 11.5 million, generation over 155 million megawatt hours of electricity, that is expected to have a system peak load of almost 30,000 MW in 2009 (ACEEE base case for Ohio).

Electricity demand in Ohio has fluctuated over the past 15 years (EIA 2009). Total consumption has grown only slightly. Total retail sales in 2007 in Ohio totaled 161.5 billion kWh. This is an aggregate figure for all sectors, including industrial, commercial and residential.

Ohio has been and likely will continue to be a modest importer of energy and likewise be dependent on out-of-state capacity. In 2007, in-state generation provided less than 97% of total Ohio retail sales, thus requiring import of approximately 3% (EIA 2008a).

Role of Demand Response in Ohio's Resource Portfolio

The DR capabilities deployed by Ohio utilities can become part of a long-term resource strategy that also includes resources such as traditional generation resources, power purchase agreements, options for fuel and capacity, and energy efficiency and load management programs. Objectives include meeting future loads at lower cost, diversifying the portfolio to reduce operational and regulatory risk, and allow Ohio customers to better manage their electricity costs.

The 2005 Energy Policy Act provisions for Demand Response and Smart Metering has lead to a number of states and utilities piloting and implementing a Smart Grid, or sometimes referred to as Advanced Metering Infrastructure (AMI). Smart Grid is a transformed electricity transmission and distribution network or "grid" that uses robust two-way communications, advanced sensors, and distributed computers to improve the efficiency, reliability and safety of power delivery and use. For energy delivery, the Smart Grid has the ability to sense when a part of its system is overloaded and reroute power to reduce that overload and prevent a potential outage situation. Principal benefits of Smart Grid technologies for DR include increased participation rates and lower costs.

The growth of renewable energy supply (and plans for increased growth) can also increase the importance of DR in the portfolio mix. For example, sudden renewable energy supply reductions (e.g., from an abrupt loss in wind) may be mitigated quickly with DR.

Assessment of Demand Response Potential in Ohio

Table 11 shows the resulting load shed reductions possible for Ohio, by sector, for years 2015, 2020, and 2025. Load impacts grow rapidly through 2018 as program implementation takes hold. After 2018, the program impacts increase at the same rate as the forecasted growth in peak demand.

The high scenario DR load potential reduction is within a range of reasonable outcomes in that it has an eleven year rollout period (beginning of 2010 through the end of 2020), providing a relatively long period of time to ramp up and integrate new technologies that support DR. A value nearer to the high scenario than the medium scenario would make a good MW target for a set of DR activities.

The high scenario results show a reduction in peak demand of 3,078 MW is possible by 2015 (8.4% of peak demand); 6,293 MW is possible by 2020 (16.4% of peak demand); and 6,471 MW is possible by 2025 (16.2% of peak demand).

The more conservative medium scenario results show a reduction in peak demand of 2,052 MW is possible by 2015 (5.6% of peak demand); 4,193 MW is possible by 2020 (11.0% of peak demand); and 4,309MW is possible by 2025 (10.8% of peak demand).

Table 11. Summary of Potential DR in Ohio, By Sector, for Years 2015, 2020, and 2025a

	Low Scenario			Medium Scenario			High Scenario		
	2015	2020	2025	2015	2020	2025	2015	2020	2025
Load Sheds (MW):									
Residential	502	1,008	1,017	837	1,680	1,696	1,172	2,352	2,374
Commercial	86	184	199	228	491	531	428	921	996
Industrial	206	415	420	464	933	944	824	1,660	1,678
C&I Backup Generation (MW)	393	817	854	524	1,089	1,138	655	1,361	1,423
Total DR Potential (MW)	1,186	2,424	2,490	2,052	4,193	4,309	3,078	6,293	6,471
DR Potential as % of Total Peak Demand	3.2%	6.4%	6.3%	5.6%	11.0%	10.8%	8.4%	16.4%	16.2%

a. See Section 3 for underlying data and assumptions.

Figure 15 shows the resulting load shed reductions possible for Ohio, by sector, from year 2010, when load reductions are expected to begin, through year 2025.

Figure 15. Potential DR Load Reduction in Ohio by Sector (MW)

These estimates reflect the level of effort put forth and utilities are recommended to set targets for the high scenarios. These estimates are based on assumptions regarding growth rates, participation rates, and program design. These factors are discussed in Chapter 3. In developing these DR potential estimates, the integration of DR with select energy efficiency activities was considered to help ensure that load impacts were not double counted. The estimated load reduction per program participant is conservatively estimated to account for increased energy efficiency in the future.

Recommendations

Key recommendations include:

- *Implement programs focused on achieving firm capacity reductions as this provides the highest value demand response.* This is accomplished through establishing appropriate customer expectations and by conducting program tests for each DR program in each year. These tests should be used to establish expected DR program impacts when called and to work with customers each year to ensure that they can achieve the load reductions expected at each site.

- *Appropriate financial incentives for the Ohio' utilities either for programs administered directly by the utilities or for outsourcing DR efforts to aggregators.* The basic premise is that a utility's least-cost plan should also be its most profitable plan. Developing these incentives poses some complexities in that MW's in that DR programs likely will be bid into PJM's DR programs and will receive financial payments from PJM. Whether this provides adequate incentives for the appropriate development of DR programs in Ohio should be examined.

- *Combine and cross-market EE and DR programs.* These can include new building codes and standards that include not only EE construction and equipment, but also the installation of addressable and dispatchable equipment. This can include addressable thermostats in new residences and the installation of addressable energy management systems in commercial and industrial buildings that can reduce loads in select end-uses across the building/facility. In addition, energy audits of residential or commercial facilities can also include an assessment of whether that facility is a good candidate for participation in a DR program through the identification of dispatchable loads. Furthermore, building commissioning and retro-commissioning EE programs that are becoming popular in many commercial and industrial sector programs have the energy management system as a core component of program delivery. At this time, the application of auto-DR can be assessed and marketed to the customer along with the EE savings from these site-commissioning programs.

- *Include customer education in DR efforts.* There is some perceived lack of customer awareness of programs and incentives. In addition, new programs will need marketing efforts as well as technical assistance to help customers identify where load reductions can be obtained and the technologies/actions needed to achieve these load reductions. Also, high-level education on the volatility of electricity markets helps customers understand why utilities and other entities are promoting DR and the customers' role in increasing demand response to help match up with supply-side resources to achieve lower cost resource solutions when markets become tight

- *Increase clarity and coordination between the Federal and State agencies and programs.* While states have primary jurisdiction over retail demand response, the FERC has jurisdiction over demand response in wholesale markets. Greater clarity and coordination between the Federal and State programs is needed. At the Federal level, both EPACT and EISA contain multiple provisions on demand response and smart grid technologies. EISA authorized a matching grant program to offset the costs of Smart Grid investments.

- *Understand that pricing may form the cornerstone of an efficient electric market.* Daily TOU pricing and day-ahead hourly pricing will increase overall market efficiency by causing shifts in energy use from on-peak to off-peak hours every day of the year. However, this does not diminish the need to have dispatchable DR programs that can address those few days that represent extreme events where the highest demands occur. These events are best addressed by dispatchable DR programs.

Macroeconomic Impacts: Impact of Policies and Programs on Ohio's Economy, Employment, and Energy Prices

Up to this point in the analysis we have examined the potential costs and benefits of implementing policies that might stimulate greater levels of energy efficiency and onsite solar energy in Ohio. The evidence suggests that smart policies and programs can drive more productive investments in energy-efficient technologies, and they can do so in ways that reduce the state's total energy bill. But the question remains, what does this mean for the state economy? Do the higher gains in energy productivity – that is, do the increased levels of efficiency investment with their concomitant reduction in the need for conventional energy resources – create a net economic boost for Ohio? Or, does the diversion of revenues away from energy-related industries negatively impact the economy? In this chapter, we explore those issues and we present the analytical results of an economic model used to evaluate the impact of efficiency investments on jobs, income, and the overall size of the economy.

A recent meta-review of some past 48 energy policy studies done within the United States suggests that if investments in more efficient technologies are cost-effective, the impacts on the economy should be small but net positive (Laitner and McKinney 2008). As shown elsewhere in the report, it turns out that from a total resource cost perspective, the benefits (i.e., the energy bill savings) outweigh both the policy costs and investments by about two and one-half times. In other words, the energy efficiency policy recommendations highlighted in the policy scenario result in a substantial savings for households and businesses compared to the costs of implementing the policies. As we also discuss below, this consumer energy bill savings can drive a significant increase in the number of net new jobs within the Ohio.[52] In fact, continued investments in energy efficiency resources would maintain the energy resource benefits for many years into the future, well beyond the period of analysis examined in this report.[53] The state therefore has the opportunity to transition its energy markets to a more sustainable pattern of energy production and consumption in ways that benefit consumers.

A quick glance at the results in Table 12 below, detail the benefits that will accrue to the state of Ohio when policies encourage a more efficient use of energy resources. Further discussion in this section will provide an overview of the DEEPER model and more detailed background information for the state of Ohio.

Table 12. Economic Impact of Energy Efficiency Investment in Ohio

Macroeconomic Impacts	2010	2015	2020	2025
Jobs (Actual)	1,582	7,928	19,506	32,061
Wages (Million $2006)	$50	$300	$851	$1,615
GSP (Million $2006)	$58	$444	$1,310	$2,559

Methodology

The macroeconomic evaluation that we report in this chapter is undertaken in three separate steps. First, we calibrate ACEEE's economic assessment model called DEEPER (Dynamic Energy Efficiency Policy Evaluation Routine) to reflect the economic profile of the Ohio economy (Laitner and McKinney 2009). This is done for the period 2006 (the base year of the model) through 2025 (the last year of the analysis). In this respect, we incorporate the anticipated investment and spending patterns that are suggested by the standard forecast modeling assumptions. These range from typical spending by businesses and households in the analytical period to the anticipated construction of new electric power plants and other energy-related spending that might also be highlighted in the forecast. Second, we transform the set of key efficiency scenario results from the policy analysis into the direct inputs which are needed for the economic model. The resulting inputs include such parameters as:

[52] As we use the term here, the word "consumer" refers to any one who buys and uses energy. Thus, we include both households and businesses as among the consumers who benefit from greater investments in energy efficiency.

[53] As we note elsewhere, the policy analysis ends in the year 2025. Yet, many of the investments we describe have a technology of perhaps 15 years. This means that investments made in 2025 would continue to pay for themselves through perhaps the year 2044 and beyond; and none of those ongoing energy bill savings are reflected in the analysis described in this chapter.

- The level of annual policy and/or program spending that drives the key policy scenario investments;
- The capital and operating costs associated with more energy-efficient technologies;
- The energy bill savings that result from the various energy efficiency policies described in the main body of the report; and
- Finally, a set of calibration or diagnostic model runs to check both the logic and the internal consistency of the modeling results.

So that we can more fully characterize the analysis that was completed for this report, we next provide a simplified working example of how the modeling is done. We first describe the financial assumptions that underpin the analysis. We then highlight the analytical technique by showing the kinds of calculations that are used and then summarize the overall results in terms of net job impacts. Following this example, we then review the net impacts of the various policies as evaluated in our DEEPER model.

Illustrating the Methodology: Ohio Jobs From Efficiency Gains

To illustrate how a job impact analysis might be done, we will use the simplified example of installing one hundred million dollars of efficiency improvements within large office buildings throughout Ohio. Office buildings (traditionally large users of energy due to heating and air-conditioning loads, significant use of electronic office equipment, and the large numbers of persons employed and served) provide substantial opportunities for energy-saving investments. The results of this example are summarized in Table 13.

The assumption used in this example is that the investment has a positive benefit-cost ratio of 2.0. In other words, the assumption is that for every dollar of cost used to increase a building's overall energy efficiency, the upgrades might be expected to return a total of two dollars in reduced electricity and natural gas costs over the useful life of the technologies. This ratio is similar to those cited elsewhere in this report. At the same time, if we anticipate that the efficiency changes will have an expected life of roughly 15 years, then we can` establish a 15-year period of analysis. In this illustration, we further assume that the efficiency upgrades take place in the first year of the analysis, while the electricity bill savings occur in years one through 15.

Table 13. Illustrative Example: Job Impacts from Commercial Building Efficiency Improvement

Expenditure Category	Amount (Million $)	Employment Coefficient	Job Impact
Installing Efficiency Improvements in Year One	$100	13	1,300
Diverting Expenditures to Fund Efficiency Improvements	$-100	12	-1,200
Energy Bill Savings in Years One through 15	$200	12	2,400
Lower Utility Revenues in Years One through 15	$-200	5	-1,000
Net 15-Year Change	$0.0		1,500

Note: The employment multipliers are adapted from the appropriate sector multipliers from IMPLAN. The benefit-cost ratio is assumed to be 2.0. The jobs impact is the result of multiplying the row change in expenditure by the row multiplier. The sum of these products yields a working estimate of total net job-years over the 15-year time horizon. To find the average annual net jobs in this simplified analysis we would divide the total job-years by 15 years which, of course, gives us an estimated net gain of 100 jobs per year for each of the 15 years. For more details, see the text that follows.

The analysis assumes that we are interested in the net effect of employment and other economic changes. This means we must first examine all changes in household and business expenditures – both positive and negative – that result from a movement toward greater levels of energy efficiency. Although more detailed and complicated within the DEEPER model, for this heuristic exercise we then multiply each change in expenditures by the appropriate sector employment coefficient (adapted from IMPLAN). The sum of these products will then yield the net result for which we are looking.

In our example above, there are four separate changes in expenditures, each with their separate impact. As Table 13 indicates, the net impact of the scenario suggests a cumulative gain of 1,500 jobs in each of the 15-year period of analysis. This translates into an average net increase of 100 jobs each year for 15 years. In other words, the $100 million efficiency investment made in Ohio's office buildings is projected to sustain an average of 100 jobs each year over a 15-year period compared to a "business-as-usual" scenario.

The economic assessment of the alternative energy scenarios was carried out in a very similar manner as the example described above. That is, the changes in energy expenditures brought about by investments in energy efficiency and renewable technologies were matched with their appropriate employment multipliers. There are several modifications to this technique, however.

First, it was assumed that only 72% of both the efficiency investments and the savings are spent within Ohio. We based this initial value on the Minnesota IMPLAN Group, Inc. (IMPLAN 2007) dataset as it describes local purchase patterns that typically now occur in the state. We anticipate that this is a conservative assumption since most efficiency and renewable energy installations are likely (or could be) carried out by local contractors and dealers. If the set of policies encourages greater local participation so that the share was increased to 90%, for example, the net jobs might grow another 15% compared to our standard scenario exercise. At the same time, the scenario also assumes Ohio provides only 40% of the manufactured products consumed within the state. But again, a concerted effort to build manufacturing capacity for the set of clean energy technologies would increase the benefits from developing a broader in-state energy efficiency and renewable energy manufacturing capability.

Second, an adjustment in the employment impacts was made to account for assumed future changes in labor productivity. As outlined in the Bureau of Labor Statistics Outlook 2006–2016, productivity rates are expected to vary widely among sectors (BLS 2007). For instance, drawing from the BLS data we would expect that electric utilities might increase labor productivity by 1.8% annually while the business and personal service sectors of the economy might increase productivity by 2.2% per year. This means, for example, that we might expect a one million dollar expenditure for utility services in the year 2025 would support only 68% of the jobs that the same expenditure would have supported in 2008, while other services sectors of the economy would support only 62% of the jobs as in 2008.

Third, for purposes of estimating energy bill savings, it was assumed that all energy prices within Ohio would follow the same growth rate as those published by the Energy Information Administration in its *Annual Energy Outlook* (EIA 2008). Fourth, it was assumed that approximately 80% of the efficiency investments' upgrades are financed by bank loans that carry an average 8% interest rate over a five-year period. To limit the scope of the analysis, however, no parameters were established to account for any changes in interest rates as less capital-intensive technologies (i.e., efficiency investments) are substituted for conventional supply strategies, or in labor participation rates – all of which might affect overall spending patterns. Fortunately, however, it is unlikely that these sensitivities would greatly impact the overall outcome of this analysis.

While the higher cost premiums associated with the energy efficiency investments might be expected to drive up the level of borrowing (in the short term), and therefore interest rates, this upward pressure would be offset to some degree by the investment avoided in new power plant capacity, exploratory well drilling, and new pipelines. Similarly, while an increase in demand for labor would tend to increase the overall level of wages (and thus lessen economic activity), the job benefits are small compared to the current level of unemployment or underemployment in the state. Hence the effect would be negligible.

Fifth, as described in the previous chapters for the buildings, industrial, and transportation end-use sectors it was assumed that a program and marketing expenditure would be required to promote market penetration of the efficiency improvements. Since these vary significantly by policy bundle we don't summarize them here but payment for these policy and program expenditures were treated as if new taxes were levied on the state commensurate with the level of energy demands within the state. Hence, the positive program spending impacts are offset by reduced revenues elsewhere in the economy.

Sixth, it should be noted that the full effects of the efficiency investments are not accounted for since the savings beyond 2025 are not incorporated in the analysis. Nor does the analysis include other benefits and costs that can stem from the efficiency investments. Non-energy benefits can include increased worker productivity, comfort and safety, and water savings, while non-energy costs can include aesthetic issues associated with compact fluorescent lamps and increased maintenance costs due to a lack of familiarity with new energy-efficiency equipment (NAPEE 2007b, 3-8). Productivity benefits, for example, can be substantial, especially in the industrial sector. Industrial investments that increase energy efficiency often result in achieving other economic goals such as improved product quality, lower capital and operating costs, increased employee productivity, or capturing specialized product markets (see, for example, Worrell et al. 2003). To the extent these "co-benefits" exceed any non-energy costs, the economic impacts of an energy efficiency initiative in Ohio would be more favorable than those reported here. Finally, although we show how the calculations would look from an employment perspective, we don't show the same kind of data or assumptions for either income or for impacts on the Gross State Product (the sum of value-added contributions to the Ohio State economy). Nonetheless, the approach is very similar to that described for net job impacts.

Impacts of Recommended Energy Efficiency Policies

For each year in the analytical period, the given change in a sector spending pattern (relative to the reference scenario) was matched to the appropriate sectoral impact coefficients. Two points are worth special note: first, it was important to match the right change in spending to the right sector of the Ohio economy; and second, these coefficients change over time. For example, labor productivity changes mean that there may be fewer jobs supported by a one million dollar expenditure today compared to that same level of spending in 2025. Both the negative and positive impacts were summed to generate the estimated net results shown in the series of tables that follow. Presented here are two basic sets of macroeconomic impacts for the benchmark years of 2010, 2015, 2020, and 2025. These include the financial flows that result from the policies described in the previous chapters. They also include the net jobs, income, and GRP impacts that result from the changed investment and spending patterns.

Table 14 presents the changes in consumer expenditures that result from these policies. While the first row in the table presents the full cost of the energy efficiency policies, programs and investments, the utility customers will likely borrow a portion of the money to pay for these investments. Thus, "annual consumer outlays," estimated at about $193 million 2010, rise to nearly $2.1 billion in 2025. These outlays include actual "out-of-pocket" spending for programs and investments, along with money borrowed to underwrite the larger technology investments. The annual energy bill savings reported in Table 14 are a function of reduced energy purchases from the many Ohio utilities and other energy providers within the state.

As we further highlight in the table that follows, the annual energy bill savings begins with a modest first year benefit of $58 million. As more and more investments are directed toward the purchase of more energy-efficient technologies, the annual consumer energy bill savings rise to about $1 billion by 2025.

Table 14. Financial Impacts from Energy Efficiency Policy Scenario

(Millions of 2006 $)	2010	2015	2020	2025
Annual Consumer Outlays	$193	$723	$1,496	$2,146
Annual Energy Savings	$111	$1,154	$2,961	$5,461
Energy Bill Adjustment Savings	$58	$267	$626	$1,059
Annual Net Consumer Savings	-$23	$431	$1,465	$3,314
Cumulative Net Energy Savings	$9	$954	$5,951	$18,980

'Annual' refers to the total that is reported in the benchmark year while 'Cumulative' is the total from previous years beginning in 2010 through the benchmark year.
Annual consumer outlays include administrative costs to run programs, incentives provided to consumers, investments in energy efficiency devices and interest paid on loans needed to underwrite the needed efficiency investments.
Annual energy savings is the reduced energy bill expenditures that benefit both households and businesses within a given year. The net savings is the difference between savings and outlays. The numbers in parentheses are losses in that specific year.

Readers should note from Table 14 that in the early years and especially as the policies ramp up quickly to stimulate a greater level of efficiency improvements, the consumer outlays outweigh the energy bill savings. In 2010, the net annual savings are negative at $-23 million and a positive $431 million by 2015. These savings mount steadily through the year 2025 by when they reach an estimated $3.2 billion net annual savings for the state as a whole. The last row of the table highlights cumulative impacts. By 2025, the net cumulative savings over the period 2010 through 2025 show a strong net positive result, reaching nearly $18.9 billion.

At this point we then have the financial flows estimated as they are distributed across the end-use sectors described earlier in the report. The question then becomes what might be the impacts on the state economy as we've been able to evaluate them for a given year using the DEEPER model. The modeling then evaluates impact on jobs and wages sector-by-sector, and evaluates their contribution to Ohio's Gross State Product (GSP), which is a sum of the net gain in value-added contributions provided by the energy productivity gains throughout all sectors of the state economy. As with the previous table on financial impacts, Table 15 highlights the net impacts for the benchmark years 2010, 2015, 2020 and 2025.

Table 15. Economic Impact of Energy Efficiency Investment in Ohio

Macroeconomic Impacts	2010	2015	2020	2025
Jobs (Actual)	1,582	7,928	19,506	32,061
Wages (Million $2006)	$50	$300	$851	$1,615
GSP (Million $2006)	$58	$444	$1,310	$2,559

Given both the financial flows and the modeling framework, the analysis suggests a net contribution to the state's employment base as measured by full-time jobs equivalent. In the year 2010 we see a net increase of 1,582 jobs which increases to a significantly larger total of 32,061 jobs by 2025. The early years of the policy scenarios show small net cost to the economy. Yet we continue to see a net increase in jobs. How is this possible?

In Ohio, the electric power and the natural gas service sectors directly and indirectly employ about 3.0 and 1.5 jobs, respectively, for every $1 million of spending. But, sectors vital to energy efficiency improvements like construction, utilize 8.5 jobs per $1 million of spending. Once job gains and losses are netted out in each year, the analysis suggests that, by diverting expenditures away from non-labor intensive energy sectors, the cost-effective energy policies can positively impact the larger Ohio economy – even in the early years, but especially in the later years of the analysis as the energy savings continue to mount.

To highlight the results of this analysis in a little more detail, Figure 16 provides year-by-year impacts on net jobs within Ohio. Figure 17 highlights the anticipated net gain to the state's wage and salary compensation and Gross State Product, both measured in millions of 2006 dollars.

Figure 16. Net Job Impacts for Ohio (2008-2025)

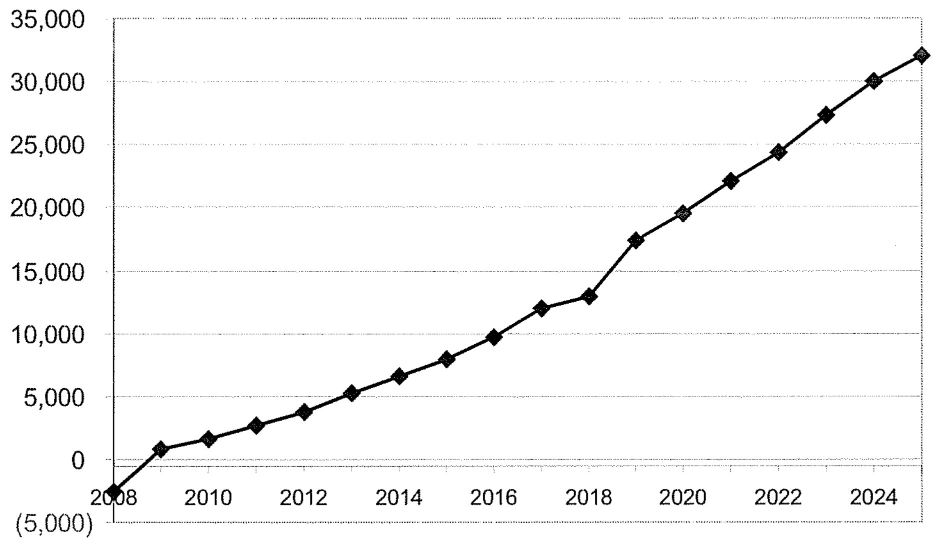
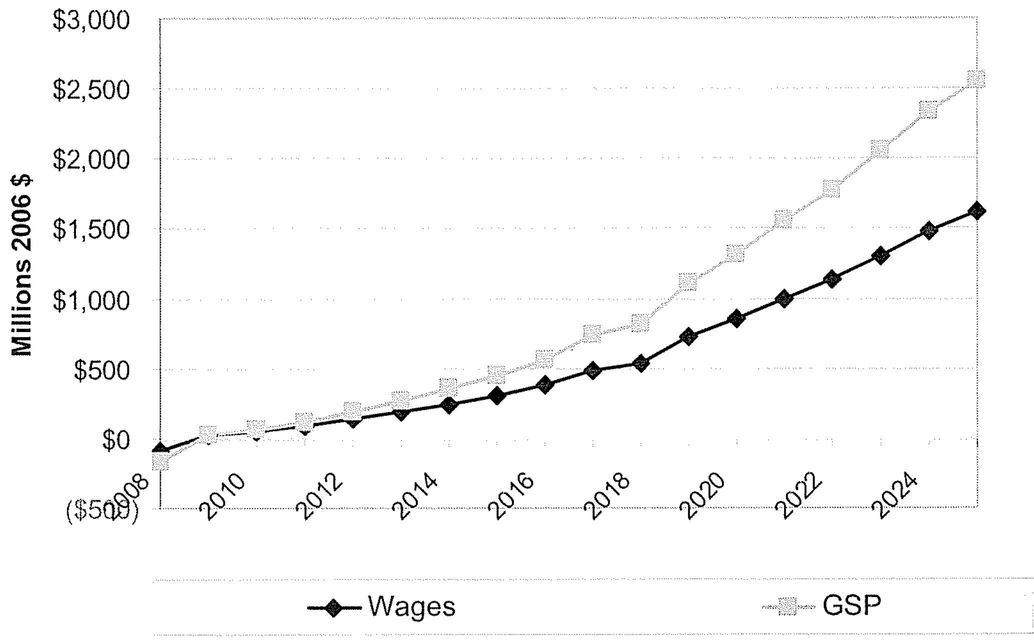


Figure 17. Wages and Gross State Product Impacts for Ohio



The end result of this policy analysis, then, suggests that an early program stimulus which drives a higher level of efficiency investments can actually increase economic impact, creating an average of 4,624 net new jobs from 2010-2015, and rising to an estimated average of 20,726 net new jobs over the last decade of the analysis. This is roughly equivalent to the employment that would be directly and indirectly supported by the construction and operation of 256 small manufacturing plants within Ohio. As indicated by Figure 17, these investments also increase both wages and Gross State Product throughout Ohio.

In short, the more efficient use of energy resources provides a cost-effective redirection of spending away from less labor-intensive sectors into those sectors that provide a greater number of jobs within Ohio. Similarly, cost-effective energy productivity gains also redirect spending away from sectors that provide a smaller rate of value-added into those sectors with slightly higher levels of value-added returns per dollar of revenue. The extent to which these benefits are realized will depend on the willingness of business and policy leaders to implement the recommendations that are at the heart of this report and found earlier in this assessment. It is also important to note that these results are not finalized. Several policy areas remain to be incorporated into the DEEPER model, including onsite solar. It is expected that finalized results will estimate a higher impact on job creation and GSP.

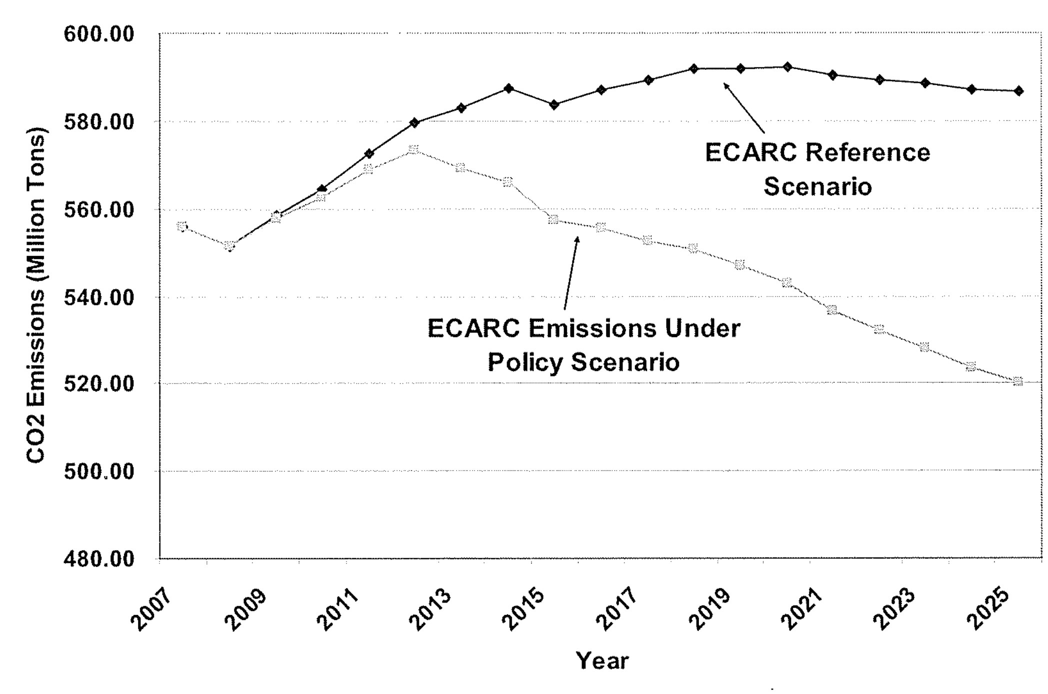
EMISSIONS IMPACTS IN POLICY SCENARIO

Meeting the demand for electricity through efficiency resources reduces electricity generation; thus, any environmental impacts that would result can be avoided. Efficiency represents a cost-effective strategy to reduce global warming emissions. One caveat of the avoided emissions from efficiency that readers should note is that Ohio imports about 3% of its electricity from outside the state.

Therefore, not all of the electricity avoided through efficiency is attributable to power plants in Ohio, but rather from the PJM and MISO wholesale power markets in which Ohio participates.

The policies we suggest would reduce carbon dioxide (CO_2) emissions in the East Central Area Reliability Council (ECARC) by 5.9 million tons in 2015 and almost 20 million tons in 2025, or 1% and 3% of total emissions in the region, respectively (see Figure 18). Through 2025, energy efficiency can reduce CO_2 emissions cumulatively by around 152 million tons. In 2006, Ohio accounted for 142 million tons of CO_2 emission, more than 26% of regional emissions (EIA 2007a). Because electricity savings from efficiency policies in Ohio will have an impact across the ECARC, we therefore estimate these CO_2 reductions from energy efficiency programs and policies relative to the entire region.

Figure 18. ECARC CO_2 Emissions in Reference and Policy Scenario

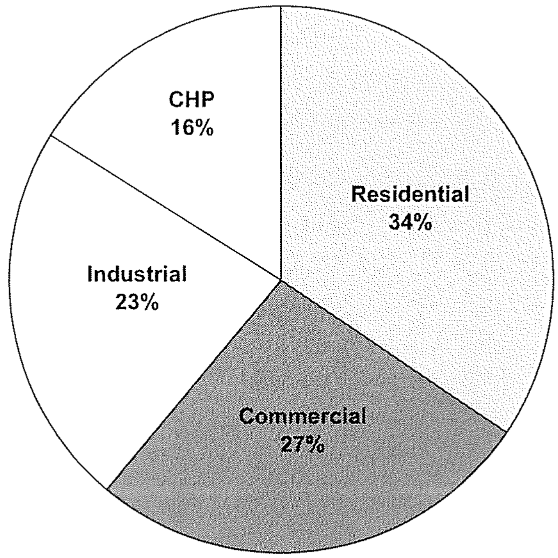


SUMMARY OF FINDINGS

Energy Efficiency Resource Potential

ACEEE's assessment of the economic potential for energy efficiency resources in Ohio estimates efficiency resources equivalent to 33% of the electricity needs of the state in 2025. Energy efficiency resources are identified across all sectors: residential, commercial, and industrial (see Figure 19), which highlights the important fact that everyone in Ohio can make contributions to improve energy efficiency across the state. Combined heat and power and demand response contribute further to the potential for both lower electricity consumption and reduced peak demand.

Figure 19. Summary of Energy Efficiency Resource Economic Potential (64,284 GWh or 33% of Projected Electricity Consumption in 2025)



Impacts of Energy Efficiency and Demand Response

In our policy discussion above, ACEEE suggested a suite of energy efficiency and demand response policies and programs that would enable Ohio to tap into its energy efficiency resource potential. The impacts of these policies and programs on electricity consumption in Ohio over the period of this analysis are shown in Figure 20. The combined effects of efficiency and demand response on overall summer peak demand are shown in Table 16 and Figure 21.

Consumer Savings

The energy savings from these efficiency policies and programs can cut the electricity bills for customers by a net $430 million in 2015. Net annual savings grow eight-fold to $3.3 billion in 2025. While these savings will require some public and customer investment, by 2025 net cumulative savings on electricity bills will reach almost $19 billion. These savings are the result of two effects. First, participants in energy efficiency programs will install energy efficiency measures, such as more efficient appliances or heating equipment, therefore lowering their electricity consumption and electric bills. In addition, because of the current volatility in energy prices, efficiency strategies have the added benefit of improving the balance of demand and supply in energy markets, thereby stabilizing regional electricity prices for the future.

Figure 20. Estimated Reductions in Electricity Use in Ohio through Energy Efficiency

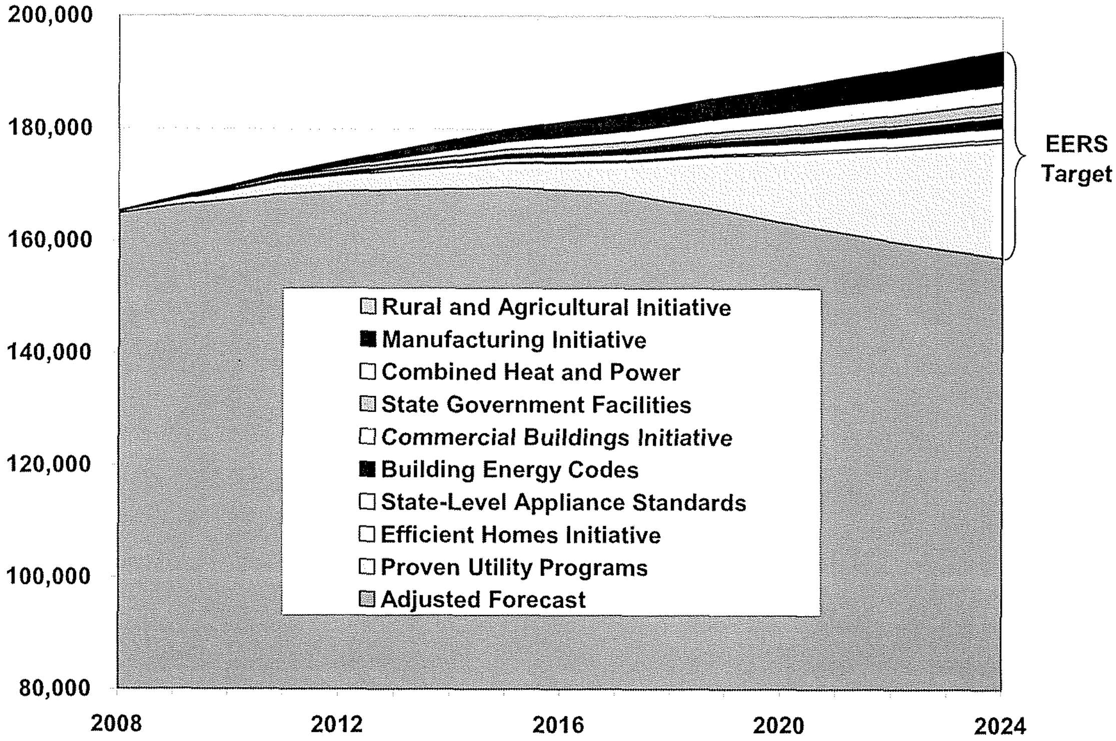


Table 16. Summary of Peak Demand Reduction Potential in Ohio

	2015	2025	% Reduction
Energy Efficiency Peak Reductions	1,550	7,081	18%
Demand Response Peak Reductions	2,064	4,335	11%
Total Peak Reductions	3,615	11,416	**29%**
% Reduction (total relative to forecast)	**10%**	**29%**	

Macroeconomic Impacts

Investments in efficiency policies and programs have the added benefit of creating new, high-quality "green-collar" jobs in Ohio and increasing both wages and Gross State Product (GSP). Our analysis shows that energy efficiency investments can create over 32,000 new jobs in Ohio by 2025 (see Table 17) including well-paying trade and professional jobs needed to design, install, and operate energy efficiency measures. These new jobs, including both direct and indirect employment effects, would be equivalent to over 300 new manufacturing facilities relocating to Ohio, but without the public costs for infrastructure or the environmental impacts of new plants.

Figure 21. Estimated Reductions in Summer Peak Demand through Energy Efficiency and Demand Response (2025 peak reduction = 11,416 or 29%)

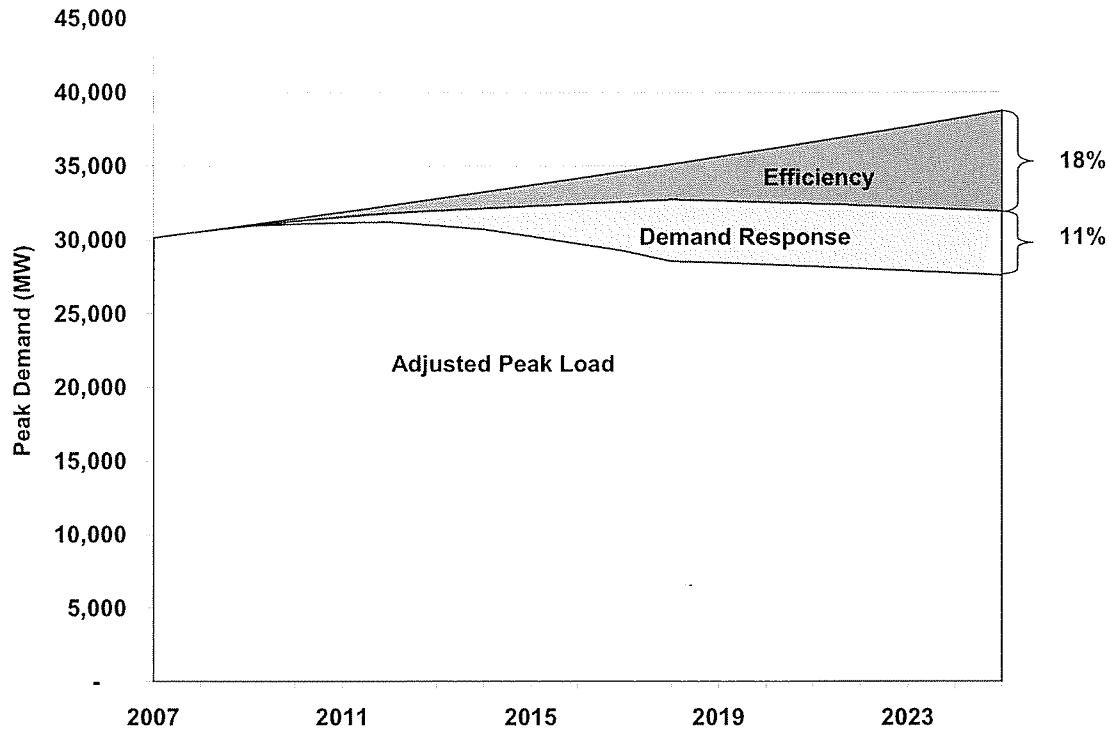


Table 17. Economic Impact of Energy Efficiency Investments in Ohio

Macroeconomic Impacts	2015	2025
Jobs (Actual)	7,928	32,604
Wages (Million $2006)	300	1,615
GSP (Million $2006)	444	2,559

DISCUSSION AND RECOMMENDATIONS

ACEEE offers this report to the state of Ohio to help inform its deliberations on energy and climate change policies. We have attempted to tailor our nationwide experiences to the specific needs and opportunities of the state, recognizing that what is implemented with respect to programs and policies should be a decision of the citizens through their elected officials.

The objectives of this report are threefold:

- to engage various stakeholders in Ohio who have a vested interest in energy issues on the political viability of energy efficiency
- to perform an analysis of the potential for increased energy efficiency in Ohio and to make and analyze specific policy suggestions tailored to Ohio; and
- to inform the dialogue of Ohio stakeholders as energy efficiency policies and programs are considered utilizing the study's findings and to provide ongoing follow-up (as resources allow) to interested parties.

Our intention is that this report be used as a roadmap for further development of energy efficiency policies and programs. In preparing this report, ACEEE has drawn upon almost three decades of experience working on energy efficiency policies and programs. Our policy suggestions and examples of utility-run programs are based upon our assessment of "best practices." We have attempted in many places to identify resources that are available for further development, and stand prepared to assist Ohio with additional information and referrals. Ohio's policymakers must focus on what policies and program options they are committed to pursuing.

Role of Key Policymakers

The review of our policy suggestions included possible entities that are well-positioned to lead their implementation. In our prior research, we have documented that many of these policies and programs can be successfully implemented by a number of different entities, though the choice remains with the policymakers.

- ***The Governor*** – Governor Strickland has already established himself as a key figure in the advancement of energy efficiency across the state of Ohio. In August 2007, Governor Strickland announced his Energy, Jobs, and Progress plan, which effectively set the gears in motion for the introduction and subsequent passing of SB 221 in April of 2008. The Governor has the potential to implement at least parts of a number of our suggestions, including the expansion of the state and local facilities initiative. In part, the Governor's most important role may be to use his position to raise awareness among the policy community and the public as to the role of energy efficiency in utility and climate policy. The Governor will also have to play a role in securing long-term funding for state-sponsored initiatives.
- ***Legislature*** – The Ohio legislature has already played a key role in setting Ohio on its current energy path and will continue to play a pivotal role because of its ability to both fund and direct energy policy for the state. The legislature should consider such steps as adoption of state appliance and equipment efficiency standards; updating state residential and commercial energy codes as they are introduced by the IECC and ASHRAE; and allocating funds from the American Recovery and Investment Act. The legislature will also have to secure long-term funding for these initiatives.
- ***Electric Utilities*** – Ohio's investor-owned utilities are legally obligated to meet the efficiency requirements set by SB 221. The suite of policies we have suggested the PUCO allow to contribute towards the EERS will meet a significant part of the target so that utilities will only have to rely on their own proven programs to meet 12% of the 22% consumption savings target.
- ***Ohio Air Quality Development Authority*** – The OAQDA, through its bond underwriting capability, has the authority to fund programs directly impacting activities that contribute to air pollution within the state. Because energy efficiency has the ancillary benefit of reducing emissions attributable to electricity generation, OAQDA funding can be utilized for a number of efficiency programs.
- ***State Agencies*** – Various agencies would have a significant role in implementing provisions such as the advanced buildings initiatives, as well as the manufacturing and agricultural/rural initiatives. These agencies would also be involved in the education and outreach effort that would be crucial in engaging the state's consumers with the information needed for them to make informed energy investment decisions. Funding from the American Recovery and Reinvestment Act will be available for these purposes, but there will be a need to secure long-term funding as well. Long-term funding could come from future climate change legislation mandated at the federal level or through utility rates.
- ***Local Governments*** – Local government entities are uniquely positioned to implement several important policies such as building energy codes and programs for local government facilities (as discussed in Elliott and Eldridge 2007). Funding from the American Recovery and Investment Act will be available for these purposes.

- ***State Educational System*** – With the identification of Ohio's workforce as a key requirement, the state educational system would be responsible for ensuring that a trained workforce is developed to fill the jobs that increased investment in energy efficiency would create.

Industrial Self-Direct

SB-221 includes a provision, which can be implemented at the option of the PUCO, to allow for large electric consumers to opt-out of paying utility energy efficiency program charges if they implement energy efficiency projects at their own facilities at their own expense. The motivation for this results from a perception by some large consumers that the programs offered to them by the utilities are not responsive to their needs (ELCON 2008). The history of this type of provision has been mixed, with some self-direct programs not requiring rigorous evaluation, measurement and verification of the customer implemented measures. In these instances, it's been very difficult to determine if the savings projected by industrial customers has been achieved.[54] To address this concern, the PUCO could require that the customer who chooses to self-direct retain at their own expense a commission-approved contactor to undertake an assessment of the savings to ensure that they are in compliance with their savings obligation.

As an alternative, the PUCO and the utilities can ensure that program offerings are responsive to the needs of the manufacturing sector. This approach is consistent with our recommendation for the establishment of the *Ohio Manufacturing Initiative* that we have proposed as part of the suite of innovative policies, based on our consultation with Ohio industrial trade associations. We see this approach as preferred for both the state – since industrial energy efficiency savings tend to be lower cost than other sectors – and the customers – since they receive the benefits of a program tailored specifically to meet their needs. It also helps ensure that the lessons learned and institutional knowledge gained by administering efficiency programs to the largest industrial customers benefits future industrial customers. This approach has worked well with the Oregon Energy Trust and BC Hydro in Canada.[55]

Program and Policy Implementation

Beyond the obligation of Ohio's private utilities to implement energy efficiency, there are many entities in the electricity market, both consumers and providers, which have voiced their support for energy efficiency and are willing to invest voluntarily. Leveraging these other market players could increase the prevalence of energy efficiency significantly. For example, the OMA, through its Energy Efficiency Collaborative, and the University of Dayton, through its IAC program, are beginning or have already begun to deliver services to the manufacturing community, so building on these existing efforts allows expanded services to be delivered more quickly. Our meeting with the Ohio Hospital Association revealed that integrating distributed generation, such as combined heat and power, into their operations could reduce their operating costs in light of their perpetual need for massive amounts of electric power. Buckeye Power, Inc., an electric cooperative owned by Ohio's 25 rural electric cooperatives, has also taken a keen interest in energy efficiency, though demographics and the sparse service areas of these cooperatives preclude them from achieving the level of savings expected from Ohio's IOU's.

Evaluation, Measurement, and Verification (EM&V)

The implementation of energy efficiency policies and programs must include a mechanism that emphasizes transparency and ensures success. Funding of and participation in efficiency programs will only be guaranteed, however, if policymakers and consumers are cognizant of the benefits these programs are delivering, which, of course, also requires that these benefits be verified. An inherent

[54] From discussions between Anna Chittum and multiple industrial energy efficiency program managers, January – March 2009.
[55] Ibid.

element of any attempt to advance energy efficiency is an indigenous entity dedicated to the evaluation, measurement, and verification of efficiency programs. As the utility regulatory body, the PUCO is ideally situated to command this role. However, adding EM&V to the PUCO's obligations would require time to organize and staff so that it would be able to fully engage in its new duties.

Allocation of Benefits from Energy Efficiency

Reducing total electricity consumption is an effect of energy efficiency that avails customers through lower electricity bills, but can be a bane for utilities as lower sales mean lower revenues. Naturally there is concern from IOU's and their shareholders that, over time, dwindling revenues could impede utilities' ability to provide energy services due to decreased earnings or financial margins. To counter this phenomenon, IOU's have expressed their interest in pursuing cost recovery in order to guarantee a return on their efficiency investments, which can be done through decoupling, performance-based incentives, or some other rate mechanism (EPA 2007b). ACEEE does not support one method over another, but it is vital that energy efficiency benefits be allocated fairly between ratepayers and shareholders alike. Nonetheless, it is also important that utilities earn profits equivalent to what they would under a supply-only scenario.

CONCLUSIONS

The State of Ohio is poised to make great strides in expanding efficiency throughout the state. As this report documents, there is tremendous potential for Ohio to become a national leader in efficiency and to take advantage of the numerous cost-effective energy efficiency and demand response opportunities that exist in the state. Nonetheless, Ohio does have some difficult decisions to make with regards to its energy future. Faced with severe budgetary constraints and a slumping economy, there may be an inclination to dispel energy efficiency in light of the present conditions. Regrettably, the ramifications of a bleak economic outlook have already begun to impact important energy policy decisions, such as the state's rollback of its building energy codes. It is therefore extremely important that the momentum created by the establishment of the aggressive EERS target by legislation included in SB 221 not be lost. This legislation has sent a strong signal of Ohio's intent, which in large part contributed to its respectable ranking in ACEEE's 2008 state energy efficiency scorecard. However, Ohio will have to continue to balance its priorities in order for energy efficiency to affect its economy as beneficially as this report highlights.

The various energy efficiency and demand response policies we suggest have been successful in other states at delivering efficiency resources and reducing consumer electric expenditures. We estimate efficiency can meet 122% of the increase in the state's electricity needs over the next 17 years, while meeting 188% of the increase in peak demand and reducing emissions by over 12%. What is more, these policies and programs can accomplish this at a lower cost than building new supply infrastructure, while simultaneously creating over 32,000 new, high-quality "green collar" jobs by 2025.

Our suggestions are intended to be the starting point for dialog among stakeholders on how to realize the demand-side efficiency resource potential in the state, particularly given the economic challenges it faces. ACEEE's suggestions are based on our review of existing opportunities and stakeholder discussions, and reflect proposals that we think are politically viable. However, it is important to note that these suggestions will not necessarily meet all of the state's future energy needs. While energy efficiency is perhaps the only new energy resource available that can be deployed quickly in the short term and continue to contribute significantly into the long term, the state will still require additional resources to meet any new load while replacing older, dirtier generation plants as they are retired. Furthermore, additional policies and programs exist that could be implemented to realize even more of the available energy efficiency resources. Ultimately, energy efficiency can delay the immediate need for investments in infrastructure, allowing Ohio the time to rigorously consider its future resource choices.

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APPENDIX A – REFERENCE CASE

A.1. Projection of Electricity Consumption and Peak Demand

The development of the reference case for Ohio is the foundation of the quantitative analysis of the report. The first task in developing an energy efficiency and demand response potential assessment is to determine a reference case forecast of energy consumption, peak demand, and electricity prices in the state in a "business as usual" scenario. As with all forecasts, they are subject to significant uncertainty, particularly in times such as we are in when the economic outlook is a major unknown. It is however important to understand that while the forecast may affect the final numbers resulting from the analysis, that the forecast has very minor impact of the effectiveness of the proposed policies, particularly in the long-run.

When developing a reference case, it is preferable to use forecasts that are specific to the state or region and that are agreed upon by key stakeholders. Initially we used a report released by the Public Utilities Commission of Ohio (PUCO) in 2008 forecasting electricity consumption and peak demand over the 2008-2027 period, which included historical data starting in 2002. However, the historical data from the PUCO forecast were not consistent with consumption data from the Energy Information Administration's *Electric Power Annual* (EIA 2007b) and *Annual Energy Outlook* (EIA 2007c) and neither reflected current economic conditions in their projections. We elected to use the forecast we estimated based on the EIA's data until we were able to clear up the reasons for the variations between the PUCO and the EIA forecasts.

In the meantime, several key stakeholders voiced their concern about basing our forecast off data from the EIA as opposed to using the PUCO forecast. Ultimately the PUCO responded about the variations, noting that the 2008 forecast had been made with data several years old and providing an updated forecast using the most recent data. However, the updated forecast has not yet been published and did not include a breakdown of electricity consumption by sector. We thus chose to continue to use the forecast we developed based on the EIA data because it was not significantly different in the long-term from the PUCO forecast. We also felt our forecast was more current and that we had a greater understanding of the strengths and deficiencies of our forecast than we did with the PUCO forecast.

A.1.1 Electricity Consumption Forecast

To develop our electricity consumption forecast we used a number of data sources. For historical sales, covering 2002 through 2007, we used data from the EIA's *Electric Power Annual* (EIA 2007b), which publishes consumption data for all states individually. To estimate projected consumption, we then applied sector-specific growth rates, derived from the EIA's *Annual Energy Outlook* (EIA 2007c) forecast for the East Central Area Reliability Coordination Agreement (ECARC), to actual 2007-year electric sales data. Using this methodology, we estimated total electricity consumption in the state to grow in the reference case at an average annual rate of 1.0% between 2008 and 2025, and 1.0%, 1.6%, and 0.4% in the residential, commercial, and industrial sectors, respectively (see Figure 5). Total electricity consumption in the three sectors in 2007 was 161,547 GWh and in the reference case grows to 177,954 GWh in 2015 and 193,945 GWh in 2025 (PUCO 2009).

A.1.2 Peak Demand Forecast

To forecast peak demand we adjust our data from the electricity sales forecast using a system load factor, which we assumed to be 60.0%. Using this methodology, we estimate peak demand growing at an average annual rate of 1% over the 2008-2025 period. In 2008, peak demand is expected to reach 33,705 MW increasing to 36,586 MW by 2015 and 39,770 MW in 2025.

Table 18. Retail Electricity Sales and Peak Demand Forecast

	2010	2015	2020	2025	Average Annual Growth Rate
Electricity (GWh)					
Residential	56,925	60,011	63,217	65,748	**1.01%**
Commercial	50,571	55,383	59,662	64,510	**1.63%**
Industrial	60,112	62,559	62,974	63,688	**0.43%**
Total	**167,607**	**177,954**	**185,853**	**193,945**	**0.98%**
Summer Peak Demand (MW)					
Total	**34,497**	**36,586**	**38,612**	**39,770**	**0.98%**

A.1.3. Ohio Population Forecast

Population estimates were needed for this analysis to determine per-capita sales data. We consulted Economy.com (2008) for data on population in the State of Ohio. According to this source, population in Ohio will grow at an average annual rate of about 0.21%.

Table 19. Ohio Population Forecast

	2010	2015	2020	2025	Average Annual Growth Rate
Population Estimate	11,509,050	11,574,410	11,696,320	11,883,570	0.20%

A.2. Projection of supply prices and avoided costs

Synapse Energy Economics developed projections of supply prices and avoided costs used in this analysis. These estimates were developed based on key input assumptions that were developed as part of the stakeholder engagement process. Synapse then developed a simplified Electricity Planning and Costing Model to develop the projections. As noted in the main report, two set of projections were developed for the reference and moderate policy cases.

A.2.1. Caveats

The projections of production costs and avoided costs presented in this memo are based upon a number of simplifying and conservative assumptions that the stakeholder group consider reasonable for the purpose of this high-level policy study. These simplifications include use of a single annual average avoided energy costs to evaluate the economics of energy efficiency measures rather than different avoided energy costs for energy efficiency measures with different load shapes. In addition, Synapse Energy Economics considers it unrealistic to rely upon projections that exclude the cost of compliance with anticipated CO_2 emission regulations.

A.2.2. Key Assumptions

This section describes the key inputs to the electricity model that Synapse Energy Economics has developed for this project (Synapse electricity cost model), the rationale for the proposed values and the sources of those values. The final inputs are based upon a set of draft inputs developed by

Synapse[56] that ACEEE reviewed with key stakeholders in Ohio. The key substantive difference between these final input assumptions and the draft input assumptions was the use of a lower peak load factor, from 66.2% to 60.0%.

The memo also provides a description of the Electricity Cost model that we use to estimate future production costs and avoided costs.

Changes from the December 8 version, Deliverable 1A, are indicated in ***italics***.

A.2.3. Input Assumptions

The key inputs to the electricity model are presented under the following thirteen categories:

- Basic Modeling assumptions
- Base year Sales and revenues
- Base year Load and resource Balance
- In-State Base Year Generation Resource Performance and Cost Data
- New Generation Resource Performance and Cost Data
- Fuel Types
- Annual Energy and Peak Load
- Capacity retirements
- Capacity additions
- Fuel prices
- Purchased Power Costs
- Carbon Emission Costs
- Wholesale Market Prices

Basic Modeling Assumptions:

- The base year is 2007. All monetary values are reported in constant 2006 year dollars unless noted otherwise.
- The study period begins in 2008 and ends in 2030, an analysis period of 23 years.
- The reporting period is 2009 through 2025, a total of 17 years.
- The financial parameters for costing resource additions are as follows:
  - Inflation Rate. 2.50%. Rationale - the twenty year average (1987-2006) derived from the chained GDP deflator is 2.47%.
  - Nominal Discount Rate. 10.0%. This represents the value for an independent power producer with a mix of equity and bond financing. Based on a 50/50 equity/debt mix with 12% for equity and 8% for debt. Used for levelization of capital expenditures. Actual rates for specific projects will vary depending on the nature of the project and the implementing entity.

[56] Deliverable 1A Draft Input Assumptions for Electricity Cost Model, December 8, 2008.

- Real Discount Rate. ***7.32%***. Derived from the Nominal Discount Rate and the Inflation Rate.

- Income Tax Rate. Federal rate of 35% and Ohio state corporate rate of 6.8%. Property tax rate at the nominal level of 0.5% per annum of the initial plant cost (local rates vary considerably). Used for capital cost levelization.

A.2.4. Base Year Sales and Revenues

The historic sales and revenues data are obtained from the EIA's "State Electric Profile" Table 8 (http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html). This has been supplemented with data for 2007 from the EIA "Electric Power Monthly" report of March 2008 which contains data through December of 2007 (Tables 5.4 and 5.5) (http://www.eia.doe.gov/cneaf/electricity/epm/epm_ex_bkis.html). The historic data indicates that Ohio is net exporter and generates about 12% more electricity than it needs. Likewise the capacity in Ohio is in excess of the in-state peak loads.

A.2.5. Base Year Load and Resource Balance

The historic sales and revenues data are obtained from the EIA's "State Electric Profile" Tables 5, 8 and 10 (http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html). This has been supplemented with data for 2007 from the EIA "Electric Power Monthly" report of March 2008 which contains data through December of 2007 (tables 1.6, 4.6, 4.20, 4.12 and 4.13) (http://www.eia.doe.gov/cneaf/electricity/epm/epm_ex_bkis.html).

Our forecasts of future net imports and exports of electricity are based on this reference year data and thus are consistent with the existing transmission system. We did not model or forecast projected changes in transmission transfer capability. Instead, our model assumes that future imports and exports will be at the same relative level as in the recent past and that transmission transfer capability will change in the future to match load growth and that level of relative imports and exports.

A.2.6. In-State Base Year Generation Resource Performance and Cost Data

From the above EIA data, we have the generation, CO_2 emissions and fuel costs for each generating group. From that we can derive the average heat rate for each group and the fuel component of the generation costs. To that we add typical industry values for O&M. Also from that EIA data we have the historic capacity factors associated with resource group. Those historic patterns are used to set the basis for future performance.

The capacity factors used are the historic average for all plants using a given fuel in the state. Some newer plants do much better, but because there is so much coal capacity in Ohio some older coal plants must cycle and follow load. The data includes average historic emission rate data for all pollutants. Emission allowance costs for pollutants, other than CO_2, are reflected in the O&M costs.

A.2.7. New Generation Resource Performance and Cost Data

For new generation resources we have used the technology parameters from the AEO 2008 Assumptions document. For capital costs we have used our professional judgment based on a number of sources to reflect current cost expectations for new construction. The costs represent the all-in costs, including construction financing costs, as of the year of operation. No CO_2 retrofit costs are assumed other than the allowance cost of CO_2 emissions. Fixed costs of new capacity are allocated over the generation from that new capacity based on the expected operating capacity factor of the new resource.

A.2.8. Fuel Types

We use the three basic fuel types as specified in the EIA documents (Coal, Petroleum and Natural Gas) with the addition of nuclear and biomass.

A.2.9. Annual Energy and Peak Load

For energy and peak loads we have used the ACEEE Reference Case Forecast as of 11/24/08 that *increases historic load at the rates as represented in the* AEO 2008 report for the East-Central region. A system load factor of ***60%*** based on 2007 load data is used to produce future peak loads based on forecasted energy use.

A.2.10. Capacity Retirements

There is very little information about future plant retirements and a variety of unknown circumstances may either work in favor of or against individual plants. We have attempted to reflect the generation retirements (Future Deactivation) posted on the PJM website *as well as the aging of plants in future* years. Ultimately we forecast modest gradual retirement of existing resources in the model. But it is quite likely that many existing plants will be retrofitted and their lives extended.

A.2.11. Capacity Additions

In order to meet future load growth, new generation resources must be added to the existing generation mix.

The electricity model is not a capacity expansion model that optimizes capacity additions by choosing among a set of resource alternatives to develop a least cost expansion plan. Instead, we will add new resources "manually" to meet reserve needs. Our analysis will consider three sets of additions:

- Planned Additions—Near-term proposed new additions or uprates to existing plants that are in development or advanced stages of permitting and have a high likelihood of reaching commercial operation;
- RPS Additions—Renewable generators that are added to meet existing or anticipated renewable portfolio standards (RPS) in each state; and,
- Generic Additions—New, generic conventional resources that are added to meet the residual capacity need after adding planned and RPS additions.

<u>Planned Additions</u>

Description: Our near-term entry forecast is guided by the projects in the PJM Interconnection Queue plus the expected addition of some additional future coal resources based upon market conditions in MISO and in Ohio in general based on the types of projects in the PJM queue. Looking at the 2010-2013 period for Ohio, the mix is about 85% coal, 13% wind and 2% for a mix of various other types. Based on this we have added 2,200 MW of new coal capacity by 2012. For PJM as a whole though, the queue is 66% natural gas and new natural gas generation is also likely in Ohio depending on load growth and other factors.

Data Sources: PJM Interconnection Queue Requests.

<u>AEPS Additions</u>

In 2008, Ohio enacted S.B. 221 establishing an Alternative Energy Portfolio Standard (AEPS) (enacted 5/1/2008 and effective 1/1/2009) with alternative energy and renewable generation requirements. The renewable requirement takes effect in 2009 and increases to a target of 12.5% by 2024. The solar component of this requirement increases to 0.5% of retail sales in that target year.

Eligible renewable resources are defined to include the following technologies: solar photovoltaics (PV), solar thermal, wind, geothermal, biomass, biologically derived methane gas, landfill gas, certain non-treated waste biomass products, fuel cells that generate electricity and qualified hydroelectric facilities.[57]

The specific mix of these resources is not known, but we have assumed for the renewables (less the solar component) that 1/3 of the energy will come from wind and 2/3 from biomass.

The operating characteristics are based on AEO 2008 and Synapse estimates derived from experience elsewhere in the US.

Generic Additions

In order to reliably serve the forecasted load in the mid- to long-term portion of the forecast period, new generic additions will need to be added to the model. A range of generation technologies was initially considered for this purpose, including gas/oil-fired combined-cycle, gas/oil combustion turbines, conventional coal, and nuclear. We use the mix represented in the PJM Interconnection Queue as the guide.

Generic additions based on requirements after the AEPS additions specified above are based on meeting a system-wide reserve goal. For these generic additions we use a mix of 30% conventional coal, 35% NGCC and 35% gas peakers.

A.2.12. Fuel Prices

We start with fuel prices reported for the base year of 2007. In general the price forecasts are basically long-term reflecting underlying conditions as presented in the Annual Energy Outlook of 2008 (Table 64). We have however updated those AEO forecasts of natural gas and crude oil prices based on market conditions as of 11/13/2008.

We used several sources to reflect current prices through mid 2008, and expectations for the future.

- For natural gas our projection of wholesale prices in Ohio for the next twelve years is equal to the Henry Hub price per the NYMEX futures as of November 13, 2008 plus a basis differential based on the state and Henry Hub prices in the reference year. After that point we apply the relative price trends from the AEO 2008 modeling.

- Petroleum prices are set at a historically determined multiple of natural gas prices.

- For coal we use the reported base year cost scaled by the relative year to year changes from AEO 2008.

A.2.13. Power Purchase and Sale Prices

Ohio utilities operate in two wholesale electricity markets. AEP and Dayton Power & Light operate in PJM, while Duke Ohio and FirstEnergy operate in MISO. The prices for wholesale electric energy delivered in Ohio from each of those two markets are very similar. Using 2007 as the reference year, the annual average energy price at the PJM Ohio Hub was $46.18/MWh while the annual average prices to FirstEnergy from MISO was $45.57/MWh in the Real Time market and $46.13/MWh in the Day Ahead market. Thus the price for the PJM Ohio Hub is a reasonable estimate of wholesale energy prices to Ohio for either ISO.

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[57] Information obtained from DSIRE (Database of State Incentives for Renewables & Efficiency). *Ohio Incentives for Renewables and Efficiency – Alternative Energy Resource Standard.* 12/5/08 at http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=OH14R&state=OH&CurrentPageID=1&RE=1&EE=1

This wholesale energy market price is applied to the interstate net purchase/sale of energy and thus is only a relatively small factor in the final model results. As noted earlier, our model assumes that future imports and exports will be at the same relative levels as in the recent past and that prices for those imports/exports will follow the same trajectory as average prices in Ohio.

The price forecast is discussed in Section 13 below.

A.2.14. Carbon Emission Costs

Carbon compliance costs are set at the Synapse 2008 mid-case level (see Schlissel 2008).

A.2.15. Wholesale Market Prices

Since much of Ohio operates within the deregulated PJM and MISO markets, any changes in load will be reflected as savings or costs based on those market prices. This consists of two major components - the Energy and the Capacity markets.

The starting point for the market energy price forecast are the PJM futures market Energy futures for the PJM Western Hub are traded in NYMEX and are available through 2012. However those prices are then adjusted to reflect Ohio markets. The first step is to calculate the differential between the Ohio and the PJM Western Hub. The calculations begin with the actual 2007 price for the PJM Ohio Hub, which was $46.12/MWh. This annual average price was $13.59 below the 2007 annual average price for the PJM Western hub. Also as noted in Section 11, the 2007 Ohio energy prices in both PJM and MISO were nearly the same, so this forecast is applicable for the entire state. Our forecasts of prices for the Ohio consist of futures prices for the PJM Western Hub plus the "basis differential" between the PJM Western Hub and the Ohio markets. This represents a whole state energy price consistent with historic data.

For the capacity cost we use the RTO prices from the PJM RPM auction which are also available through 2012. The energy and capacity prices are then combined to produce a total market-based avoided cost.

The market price is an approximation that reflects general behavior, but does not capture the details of any specific purchase and sale agreements. This price also only applies to the interstate net purchase/sale of energy and thus only a relatively small component of the final model results.

A.3. Electricity Planning and Costing Model

This model was developed by Synapse for ACEEE's clean energy state studies.

A.3.1. Background

ACEEE has initiated a series of state-specific "Clean Energy" potential studies through which it will work with key stakeholders in order to build a common understanding of, and consensus on, the role that clean energy resources, i.e., energy efficiency and demand response, can play in meeting the future electricity end-use requirements in each state, the economic benefits of treating those resources as the "first fuel" for meeting future requirements and the policies for maximizing reliance upon those resources. The time horizon for the studies is through 2025.

In each of those studies ACEEE will evaluate the cost effectiveness of reductions from energy efficiency and demand response, and will also demonstrate the benefits of those reductions to all consumers in the state by estimating retail prices in the long-term under a clean energy Policy Case.

ACEEE retained Synapse to provide three deliverables to support these studies

- projections of long-term wholesale electricity supply prices under a reference, or business-as-usual case;
- credible, consistent, "high-level" estimates of avoided electric energy ($/kWh) and capacity costs ($/kW-year); and
- projections of long-term electricity supply prices under a clean energy policy case.

In light of time and budget constraints, and the policy nature of these studies, ACEEE requested that Synapse develop and apply an electricity planning and costing model that would produce accurate "high-level" estimates of each of these deliverables in a well-documented, transparent manner.

In order to satisfy the ACEEE request, Synapse had to develop an electricity planning and costing model that would be:

- applicable to planning and costing from a state perspective, although most electric utility operations cross state boundaries;
- applicable from state to state, although some states are part of deregulated multi-state markets while others operate under traditional utility regulation;
- applicable using public data;
- inexpensive to setup and run; and
- relatively transparent.

Synapse has developed an EXCEL based planning and costing model with these characteristics.

A.3.2. Methodology

The model begins with an analysis of actual physical and cost data for a base year, develops a plan for meeting projected physical requirements in each future year of the study period and then calculates the incremental wholesale electricity costs associated with that plan. (Incremental to electricity supply costs being recovered in current retail rates).

A.3.3. Base Year Data

The actual data for the base year, and prior years, provides our starting point. That dataset contains historical data in the following categories:

1. Recent year summary statistics.
2. Listing of the ten largest plants in the state.
3. Top five providers of retail electricity
4. Electric capability by primary energy source.
5. Generation by primary energy source.
6. Fuel prices and quality.
7. Emissions.
8. Retail sales and revenues by customer class.
9. Retail sales by various provider types.
10. Supply and distribution of electricity.

This data enables us to characterize the electric supply system and its costs for a given state. For example the capacity, generation and capacity factor, average heat rate and fuel costs for different classes of resources. We can also calculate the retail margin from this data, i.e., the margin between average retail rates and variable production costs. The retail margin reflects the transmission and distribution costs being recovered in retail rates plus the fixed generation costs being recovered in those rates. This data is a very broad brush since the resources are grouped by fuel type and their operation is not characterized in great detail.

A.3.4. Future Years

We begin with the forecast of annual demand and energy in each future year provided by the ACEEE stakeholder group.

Next we develop a physical plan to meet the load in each of those future years. This is done in the model via the following steps:

1. Derive annual capacity and generation requirements from forecast of retail annual demand and energy, and reserve margins,
2. Determine the relative quantities of annual capacity and generation to be provided by in-state and out-state resources based on the current mix of in-state and out-of state resources,
3. Estimate resource retirements. It is quite difficult to predict the timing of actual plant retirements, but it is reasonable to assume that some older facilities will be retired during the study period. We assume gradual retirement of existing resources over time based on typical operating lifetimes. This is explicitly specified in the input data section and can easily be modified if more specific data becomes available.
4. Estimate the capacity, timing and timing of new generation additions, in-state and out of state. Our model is not a capacity expansion model and therefore does not make capacity additions "automatically." Instead, after we include "planned" capacity additions, we add enough "generic" capacity additions to maintain the reserve margin. Our generic additions are a mix of peaking, intermediate and baseload units that maintains the historical mix of those categories in the state. This approach is transparent as the additions are explicitly specified in the input data section.
5. Calculate the quantity of annual generation from each category of capacity, existing and new, in-state and out of state. The estimated quantity of generation from each category of capacity is derived from the operating capacity factors. These are generally based upon economic dispatch, i.e., dispatch from each category in order of increasing variable production costs

A.3.5. Calculate Production Costs

The model calculates the average production costs, i.e., energy plus capacity, for the particular case in the Production Model worksheet.

States with Regulated Wholesale Markets

For states with regulated wholesale markets the Production Model worksheet calculations are made as follows:

6. Calculate total cost of generation from existing in-state resources, purchases from out-of-state resources, and new in-state resources.
    a. The unit production costs of existing in-state generation includes variable operating costs plus fixed costs.[58] The aggregate cost of generation from these resources decline over time as existing coal, oil and gas plants are retired, while the existing nuclear plants with low operating costs continue operation;
    b. The unit production costs of new in-state generation consists of the levelized capital cost of new capacity additions plus their variable operating costs. The capacity cost of new capacity additions are levelized using the capital recovery factors developed in the Capital Recovery Calculation (CRC) worksheet.

[58] For existing resources fixed costs are estimated on an aggregate basis based on the base year difference between fuel and other variable costs and the retail revenues less a retail markup component.

c. The cost of power imported or exported is indexed to the generation-weighted average cost of generation from the in-state resources, i.e., existing and new. That is, the base-year import/export price changes in parallel with the in-state cost, e.g. an x% change of in-state production costs is reflected in an x% change of import/export prices. The rationale is that relative changes of in-state costs will be reflected outside the state as well.

States with Deregulated Wholesale Markets

For states with deregulated wholesale markets the Production Model worksheet calculations are made as follows:

7. The first step is to calculate the reference year market prices for the state being studied. The next step is to calculate the relationship between those state prices and market location for which future prices are available. The third step is to then apply that relationship to the futures prices to produce a forecast for market prices in the study state.

A.3.6. Calculate Avoided Costs

States with Regulated Wholesale Markets

For states with regulated wholesale markets the Production Model worksheet calculates the total avoided costs, avoided capacity costs and avoided energy costs via the following steps:

8. Total Avoided Costs. The worksheet calculates "all-in" avoided costs that include both energy and capacity costs.
   a. Years 1 to 5. For the first five years the avoided costs are a mix of avoided dispatch of existing resources and avoided total cost of new resources that would otherwise come-on-line during that period. The percentage of new resources included in that mix is phased-in, starting at 0% in year 1 and rising to 100% in year 5.
   b. Year 6 onward. After year 5 the avoided costs in each year equal the average total costs of new resources in that year. This calculation assumes that the capital costs of new resources are avoidable either through avoiding their actual construction or through recovery from revenues from off-system sales.
9. Avoided capacity cost. To estimate the avoided cost of capacity only we use the proxy plant approach which is used by several ISOs. This avoided capacity cost is based upon cost of "capacity only" from a new gas combustion turbine "peaker" unit. Basing avoided capacity cost on the capital cost of a new peaker is a commonly accepted method.
10. Avoided Energy Cost. The avoided energy cost is the total avoided cost from step 8 minus the avoided capacity cost from step 9

States with Deregulated Wholesale Markets

For states with deregulated wholesale markets the Production Model worksheet calculates the total avoided costs, avoided capacity costs and avoided energy costs differently for different time-periods.

11. Near-term years for which futures prices are available, e.g. first 4 to 5 years.
    a. Avoided energy cost – This is calculated from the energy futures market prices with appropriate historic-based adjustments for the state service area.
    b. Avoided capacity cost – This is based on the available appropriate capacity market results.
    c. Total avoided cost – This is obtained by combining the avoided energy cost with the avoided capacity cost using the base year system load factor to arrive at the combined total avoided cost on a per MWh basis.

12. Long-term years for which futures prices are not available. After the period for which futures are available, the total avoided costs, avoided capacity cost, and avoided energy cost are developed in the same manner as for regulated states, in steps 8, 9 and 10.

A.4. Reference Case Electricity Supply Prices and Avoided Costs

This section presents Synapse's projections of *Reference Case* electricity supply prices and avoided costs for Ohio. The projections are outputs from the electricity costing model that Synapse has developed for this project. The inputs to the model and the structure of the model are described above.

A.4.1 Reference Case Electricity Supply Prices

There reference case load forecast, load forecast, and supply prices are presented in Table 20. The supply forecast exceeds the load forecast by the level of estimated losses in transmission and distribution. The supply prices include the projected incremental generation costs each year, the retail margin each year and the resulting total average retail rate.

A.4.2. Avoided Electricity Costs

The avoided costs are presented in Table 21. The avoided capacity costs are presented in $/kW-year while the avoided electric energy costs are given in ¢/kWh.

Table 20. Reference Case Load, Supply and Price Forecasts

All costs in constant 2006 dollars.

CASE:	Ohio Reference Case - 1/16/09																	
Category	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load Forecast																		
Retail Energy	GWh	165,334	167,560	169,652	172,047	174,016	175,872	177,709	179,587	180,817	182,011	183,632	185,362	186,657	188,317	189,744	191,427	193,173
Retail Demand	MW	31,456	31,880	32,278	32,733	33,108	33,461	33,811	34,168	34,402	34,629	34,938	35,267	35,513	35,829	36,100	36,421	36,753
Supply Forecast																		
Capacity Requirement	MW	39,144	39,672	40,167	40,734	41,200	41,639	42,074	42,519	42,810	43,093	43,477	43,886	44,193	44,586	44,924	45,322	45,736
Capacity Sources																		
In-State Capacity	MW	33,842	33,586	33,900	34,278	34,753	36,543	36,377	36,918	37,275	37,531	37,827	38,230	38,612	38,877	39,290	39,565	39,969
Out-of-State Capacity	MW	5,302	6,086	6,267	6,456	6,447	5,096	5,698	5,601	5,535	5,562	5,650	5,656	5,581	5,709	5,634	5,757	5,767
Total Capacity Provided	MW	39,144	39,672	40,167	40,734	41,200	41,639	42,074	42,519	42,810	43,093	43,477	43,886	44,193	44,586	44,924	45,322	45,736
Energy Requirement	GWh	178,907	181,316	183,580	186,171	188,302	190,310	192,298	194,331	195,662	196,953	198,707	200,579	201,981	203,778	205,321	207,143	209,032
Energy Sources																		
In-State Generation	GWh	155,357	154,247	155,392	156,771	158,501	167,503	168,005	171,747	174,650	177,099	179,759	182,925	185,987	188,521	191,727	194,306	197,470
Out-of-State Generation	GWh	23,550	27,070	28,188	29,400	29,800	22,807	24,293	22,584	21,011	19,855	18,948	17,654	15,995	15,256	13,594	12,836	11,562
Total Energy Provided	GWh	178,907	181,316	183,580	186,171	188,302	190,310	192,298	194,331	195,662	196,953	198,707	200,579	201,981	203,778	205,321	207,143	209,032
Supply Price Forecast																		
Average Production Cost	¢/kWh	5.01	5.09	5.18	5.24	6.53	6.86	7.06	7.29	7.51	7.72	7.92	8.12	8.30	8.50	8.70	8.89	9.09
Retail Adder	¢/kWh	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42
Average Retail Rate	¢/kWh	7.43	7.51	7.60	7.66	8.95	9.28	9.48	9.71	9.93	10.14	10.34	10.54	10.72	10.92	11.12	11.31	11.51

Table 21. Reference Case Avoided Costs

All costs in constant 2006 dollars.

CASE:	Ohio Reference Case - 1/16/09																	
Category	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Avoided Costs by costing period																		
Avoided Resource Cost	¢/kWh	5.40	5.83	5.73	6.50	7.62	8.71	8.78	8.84	8.92	9.00	9.08	9.17	9.23	9.37	9.49	9.63	9.80
Avoided Capacity Cost	$/kW-yr	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23
	¢/kWh	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43
Avoided Energy Only Cost	¢/kWh	3.97	4.40	4.30	5.07	6.18	7.28	7.35	7.41	7.49	7.57	7.65	7.74	7.80	7.94	8.06	8.20	8.37

Notes: Avoided Resource Costs represent avoided production costs (fuel, O&M, CO2) for all resources, plus levelized capital costs for new resources.
Avoided Capacity Cost in $/kw-yr is converted into an energy cost equivalent (c/kWh) using the system load factor.
Avoided Energy Cost represents Total Avoided Resource Cost less Avoided Capacity Cost expressed as energy cost equivalent.

A.5 Policy Case Electricity Supply Prices and Avoided Costs

This section presents Synapse's projections of *Policy Case* electricity supply prices and avoided costs for Ohio. The projections are outputs from the electricity costing model that Synapse has developed for this project as discussed above. ACEEE provided the Policy Case Load Forecast.

A.5.1. Policy Case Electricity Supply Prices

The Policy Case load forecast, supply forecast, and supply prices are presented in Table 22. The supply forecast exceeds the load forecast by the level of estimated losses in transmission and distribution. The supply prices include the projected incremental generation costs each year, the retail margin each year and the resulting total average retail rate.

A.5.2. Avoided Electricity Costs

The avoided costs are present in Table 21. The avoided capacity costs are presented in $/kW-year while avoided electric energy costs are given in ¢/kWh.

Table 22. Policy Case Load, Supply and Price Forecasts

All costs in constant 2006 dollars.

CASE:	Ohio Policy Case - 3/10/09																	
Category	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load Forecast																		
Retail Energy	GWh	164,884	166,312	167,280	168,382	168,889	169,108	169,299	169,528	169,117	168,675	166,959	165,374	163,380	161,788	160,009	158,514	157,114
Retail Demand	MW	31,371	31,642	31,826	32,036	32,133	32,174	32,211	32,254	32,176	32,092	31,765	31,464	31,084	30,782	30,443	30,159	29,892
Supply Forecast																		
Capacity Requirement	MW	39,038	39,376	39,605	39,866	39,986	40,038	40,083	40,137	40,040	39,935	39,529	39,154	38,682	38,305	37,884	37,530	37,198
Capacity Sources																		
In-State Capacity	MW	33,842	33,519	33,695	33,865	34,087	35,261	34,881	35,014	35,055	34,949	34,890	34,433	34,194	33,734	33,497	33,111	32,878
Out-of-State Capacity	MW	5,196	5,857	5,910	6,001	5,899	4,777	5,202	5,123	4,985	4,986	4,639	4,721	4,488	4,570	4,386	4,419	4,320
Total Capacity Provided	MW	39,038	39,376	39,605	39,866	39,986	40,038	40,083	40,137	40,040	39,935	39,529	39,154	38,682	38,305	37,884	37,530	37,198
Energy Requirement	GWh	178,421	179,966	181,013	182,206	182,754	182,992	183,197	183,445	183,001	182,523	180,666	178,950	176,793	175,070	173,145	171,528	170,012
Energy Sources																		
In-State Generation	GWh	155,356	154,009	154,658	155,292	156,106	162,272	161,747	163,558	164,934	165,638	166,507	165,554	165,561	164,564	164,581	163,915	163,954
Out-of-State Generation	GWh	23,065	25,956	26,355	26,914	26,649	20,720	21,450	19,887	18,067	16,885	14,159	13,397	11,232	10,506	8,564	7,612	6,058
Total Energy Provided	GWh	178,421	179,966	181,013	182,206	182,754	182,992	183,197	183,445	183,001	182,523	180,666	178,950	176,793	175,070	173,145	171,528	170,012
Supply Price Forecast																		
Average Production Cost	¢/kWh	5.02	5.09	5.17	5.22	6.51	6.80	7.00	7.22	7.44	7.63	7.83	8.01	8.19	8.37	8.55	8.73	8.92
Retail Adder	¢/kWh	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42
Average Retail Rate	¢/kWh	7.44	7.51	7.59	7.64	8.93	9.22	9.42	9.64	9.86	10.05	10.25	10.43	10.61	10.79	10.97	11.15	11.34

All costs in constant 2006 dollars.

CASE:	Ohio Policy Case - 3/10/09																	
Category	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Avoided Costs by costing period																		
Avoided Resource Cost	¢/kWh	5.40	5.83	5.73	6.49	7.61	8.70	8.76	8.81	8.88	8.96	9.03	9.10	9.14	9.26	9.37	9.48	9.64
Avoided Capacity Cost	$/kW-yr	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23
	¢/kWh	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43
Avoided Energy Only Cost	¢/kWh	3.97	4.40	4.30	5.06	6.18	7.27	7.33	7.38	7.45	7.53	7.60	7.67	7.71	7.83	7.94	8.05	8.21

Notes: Avoided Resource Costs represent avoided production costs (fuel, O&M, CO_2) for all resources, plus levelized capital costs for new resources.
Avoided Capacity Cost in $/kw-yr is converted into an energy cost equivalent (c/kWh) using the system load factor.
Avoided Energy Cost represents Total Avoided Resource Cost less Avoided Capacity Cost expressed as energy cost equivalent.

A.6. Responses to Questions Regarding the Avoided Cost Methodology

The process of vetting the methodology for our avoided cost analysis revealed the overall comment that "...it appears that some of the assumptions used in the analysis result in a relatively high avoided cost number." That overall comment is based upon comments regarding several specific assumptions. Following are our responses, *in italics*, to those each specific comments.

1) Basic Modeling Assumptions. Financial Parameters

a) The discount rate at (8%) seems low. Is it reflective of the new credit realities?

We use a nominal discount rate of 10% and a real discount rate of 7.32%. (There is an error on page 2 of the memo where a real rate of 5.85% is given.). We believe that these are reasonable assumptions for long-term planning.

b) Is an Allowance for Funds Used During Construction (AFUDC) for modifying the plant cost included in this analysis? As used in the calculation of installed plant capital cost, AFUDC represents the time value of money during construction and is based on an internal rate equal to the weighted cost of capital.

The installed plant cost, including construction financing, is converted into a levelized cost that appears in the market in the year the plant comes on line. We do not reflect any pre-operation construction expenses in earlier year costs or electricity prices.

3) Base Year Load and Resource Balance. Was the transmission transfer capability taken into account for the amount of imported resources?

Net imported/exported electricity is based on reference year data and thus consistent with the existing transmission system. We did not model or forecast projected changes in transmission transfer capability. Instead, our model assumes that future imports and exports will be at the same relative level as in the recent past and that transmission transfer capability will change in the future to match load growth and that level of relative imports and exports.

4) In-State Base Year Generation Resource Performance and Cost

a) Isn't the actual capacity factor shown for Coal low?

The capacity factor used is the historic average for all coal plants in the state. Some newer plants do much better, but because there is so much coal capacity in Ohio some older plants must cycle and follow load.

b) Does the dataset include any emission rate and allowance cost data for SO_2?

The data includes average historic emission rate data for all pollutants. Emission allowance costs for pollutants, other than CO_2, are reflected in the O&M costs.

5) New Generation Resource Performance and Cost

a) Is the Total Plant Cost ($/kW) overnight or installed? Does the capital cost reflect and transmission upgrades or retrofits for CO_2 control equipment?

Total plant cost is "installed," including construction interest. No CO_2 retrofit costs are assumed other than the allowance cost of CO_2 emissions.

b) Isn't the Capital Levelization Factor rather low considering the high discount rate (10%)?

The Capital Levelization Factor is reasonable since it is expressed in real dollars.

c) Are the total fixed costs of each new capacity option adjusted by its equivalent availability in order to account for differing availabilities (including seasonal derates) among the options.

Fixed costs of new capacity are allocated over its generation based on the operating capacity factor of the new resource, not its availability factor.

8) Capacity Retirements in-State. Do the projected retirements reflect any of the generation retirements (Future Deactivation) posted on the PJM website?

We have attempted to reflect those listings as well as to take into consideration the aging of plants in future years. But that all is very uncertain and has only minor effects on avoided costs per se.

9) Capacity Additions In-State

a) Are the active generation queues considered as well as the PJM Interconnection Queue that is used as a guide for the new generation capacity mix.

Yes we have tried to do so, along with the addition of some additional future coal resources to reflect conditions in MISO and in Ohio in general.

b) For the renewables, will they be based on the Ohio Renewable Portfolio Standard (enacted 5/1/2008 and effective 1/1/2009) for a target of 12.5% by year 2024?

We have done so based on our understanding of that standard.

10) Fuel Prices. Aren't the fuel prices used lower than the consensus of industry and consultants' recent forecasts?

In general the price forecasts are basically long-term reflecting underlying conditions as presented in the Annual Energy Outlook of 2008 (Table 64). We have however updated those AEO forecasts of natural gas and crude oil prices based on market conditions as of 11/13/2008.

APPENDIX B – ENERGY EFFICIENCY POLICY ANALYSIS

B.1. Electricity Savings, Peak Demand Reductions, and Costs from Policy Analysis

Table 23. Electricity Savings from Policy Analysis

	Annual Electricity Savings by Policy (GWh)	2010	2015	2020	2025	Total Savings in 2025 (%)*
	Innovative Programs & Policies					
1	Efficient Homes Initiative	4	119	327	615	0.4%
2	State-level Appliance Standards	23	593	1,423	2,003	1.3%
3	Building Energy Codes		343	880	1,707	1.1%
4	Commercial Buildings Initiative	10	133	361	715	0.5%
5	State Facilities	239	837	1,434	2,032	1.3%
6	CHP	87	1,072	2,366	3,238	2.1%
7	Manufacturing Initiative	51	1,721	3,746	5,771	3.7%
8	Rural and Ag. Initiative	9	57	106	155	0.1%
	Innovative Program & Policy Savings	**424**	**4,876**	**10,644**	**16,235**	**10.3%**
9	*Proven Utility Programs*					
	Residential	480	2,078	5,410	11,328	7.2%
	Commercial	392	1,701	4,426	9,268	5.9%
	Proven Utility Program Savings	**872**	**3,779**	**9,836**	**20,596**	13.1%
	Total Savings (Policy + Program)	**1,295**	**8,655**	**20,480**	**36,831**	**23.4%**
	Adjusted Electricity Forecast (GWh)	**166,312**	**169,299**	**165,374**	**157,114**	
	Savings (% Reduction in Reference Case)	**0.8%**	**4.9%**	**11.0%**	**19.0%**	

Notes

* Percent relative to adjusted reference case forecast

Initiative broken down into programs for existing homes and new construction. Existing homes program assumes 0.5% savings throughout
the analysis period and 1% participation rate in first year, with participation increasing by 1% annually. Savings from new construction
assumes 50% savings beyond current code (IECC 2006), thereby decreasing with the adoption of new energy codes except in 2020, where
we assume program implementation and participation has matured to allow for savings beyond the 50% savings from IECC 2018. In 2011
we assume an initial participation rate of 2.5%, doubling annually until 2014, when IECC 2012 becomes effective. We then assume a
participation rate of 20% for the remainder of the analysis period. In 2020, when IECC 2018 becomes effective, delivering 50% savings, we
1 assume 20% additional savings beyond IECC 2018 are achievable

Appliance and equipment efficiency standards were adopted at the federal level in the 2007 energy bill, which also directed DOE to set
standards for additional products in the coming years. This Scenario assumes savings from these standards, which are not taken into
2 account in the reference case load forecast. Savings and cost assumptions are from a forthcoming ACEEE and ASAP standards analysis.

We assume IECC 2009 is adopted, which goes into effect 2011, the IECC 2012 is adopted and goes into effect in 2014, and the IECC 2018,
effective 2020. We estimate that these codes achieve a 15%, 30%, and 50% energy savings improvement beyond IECC 2006 requirements,
respectively. Savings apply only to end-uses covered under building codes, which are HVAC, lighting, and water heating end-uses, or 50% of
electricity consumption in new residential construction and nearly 60% of electricity consumption in commercial buildings. We assume
enforcement of each code starts at 70% compliance in the first year, 80% in second year, and 90% in the third and subsequent years.
Buildings analysis shows $0.47 per kWh investment cost for new ENERGY STAR homes, which achieve 15% savings, and $0.32 per kWh
for new commercial buildings meeting 15% and 30% beyond code. We assume $1.5 million dollars per year to implement and enforce codes,
based on recommendations in New York (NY DPS 2007). This is similar to estimates in VA that new program costs run 2-3% of building
3 costs.

Initiative broken down into programs for existing buildings and new construction. Existing buildings program assumes 1% savings throughout
the analysis period and 1% participation rate in first year, with participation increasing by 1% annually. We assume that 68.5% of total
commercial electric floorspace is non-governmental buildings, to avoid double-counting savings attributable to state facilities program
(CBECS 2003, table C17). Savings from new construction assumes 50% savings beyond current code (IECC 2006), thereby decreasing with
the adoption of new energy codes except in 2020, where we assume program implementation and participation has matured to allow for
savings beyond the 50% savings from IECC 2018. In 2011 we assume an initial participation rate of 2.5%, doubling annually until 2014,
when IECC 2012 becomes effective. We then assume a participation rate of 20% for the remainder of the analysis period. In 2020, when
4 IECC 2018 becomes effective, delivering 50% savings, we assume 20% additional savings beyond IECC 2018 are achievable.

We estimate 31.5% of total electric commercial floorspace is government buildings, from EIA (CBECS 2003, table C17). We then assume a
5 savings rate of 20% and a participation rate of 50% over the period of the analysis.

6 We assume a $500 incentive per MW for CHP facilities.

This scenario assumes that the number of industrial assessments ramps up from 50 to 200 in first three years, that each assessment
identifies 15% electricity savings, and that 50% of identified savings are implemented. Project costs assume the average investment cost per
7 kWh from the industrial sector analysis ($0.28/kWh) and program cost is assumed to be 12.5% of projected cost savings to the end-user.

Based on similar programs and values from the State of Wisconsin Focus on Energy 2007 Semiannual Report, we assume the average cost
of conserved energy at $0.025/kWh, that program & administrative costs are 24% of the cost of investment, and that customers cover half of
8 the investment cost.

Savings for proven programs are the difference between EERS requirements and policy savings. Sector savings are then allocated based
9 on the contribution to economic potential savings of the residential and commercial sectors.

Table 24. Summer Peak Demand Reductions from Policy Analysis (MW)

Sector	2010	2015	2020	2025	Total Savings in 2025 (%)
Residential	104	637	1,771	3,801	10%
Commercial	56	328	687	1,121	3%
Industrial	26	585	1,349	2,159	5%
Total Savings (MW)	**186**	**1,550**	**3,807**	**7,081**	**18%**
% Reduction (relative to forecast)	**0.5%**	**4%**	**10%**	**18%**	

Table 25. Total Resource Costs* from the Policy Analysis (Million 2006$)

By Policy/Program	2010	2015	2020	2025
Innovative Programs & Policies				
Efficient Homes Initiative	$ 1	$ 17	$ 22	$ 27
State-level Appliance Standards	$ 26	$ 64	$ 64	$ 64
Building Energy Codes	$ -	$ 42	$ 57	$ 76
Commercial Buildings Initiative	$ 3	$ 15	$ 26	$ 40
State Facilities	$ 22	$ 22	$ 22	$ 22
CHP	$ 14	$ 124	$ 169	$ 218
Manufacturing Initiative	$ 16	$ 115	$ 115	$ 115
Rural and Ag. Initiative	$ 0.3	$ 0.3	$ 0.3	$ 0.3
Proven Utility Programs				
Residential	$ 92	$ 91	$ 397	$ 507
Commercial	$ 44	$ 43	$ 188	$ 242
Total	**$ 219**	**$ 533**	**$ 1,062**	**$ 1,312**

*Note: Total Resource Costs include total investments in energy efficiency, whether made by customers or through incentives, plus program and administrative costs.

Figure 22. Incremental Annual Savings Requirements from EERS (% and GWh)

	2009	2010	2011	2012	2013	2014	2015
Efficient Homes Initiative	1	3	8	15	27	32	34
State-level Appliance Standards	-	23	46	46	116	186	178
Building Energy Codes	-	-	60	54	54	82	93
Commercial Buildings Initiative	3	7	16	20	25	29	33
State Facilities	120	120	120	120	120	120	120
CHP	-	87	29	29	309	309	309
Manufacturing Initiative	-	51	152	304	405	405	405
Rural and Ag. Initiative	-	9	9	10	10	10	10
Policy Savings	**124**	**299**	**439**	**596**	**1,064**	**1,172**	**1,181**
Savings as Percent of Forecasted Sales	**0.08%**	**0.18%**	**0.27%**	**0.36%**	**0.63%**	**0.68%**	**0.68%**
Proven Utility Programs							
Residential	195	285	394	403	243	280	279
Commercial	159	233	322	330	199	229	228
Utility Program Savings	**354**	**518**	**715**	**733**	**442**	**510**	**507**
Total Savings (Policy+Progam)	**479**	**817**	**1,155**	**1,329**	**1,506**	**1,682**	**1,688**
EERS Annual Savings Requirements (%)	0.30%	0.50%	0.70%	0.80%	0.90%	1%	1%
EERS Incr. Annual Svgs. Requirements (GWh)	**479**	**817**	**1,155**	**1,329**	**1,506**	**1,682**	**1,688**
Difference (%)	0.2%	0.3%	0.4%	0.4%	0.3%	0.3%	0.3%
Difference (GWh)	**354**	**518**	**715**	**733**	**442**	**510**	**507**

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
35	38	42	45	48	51	54	57	61	64
170	170	169	169	152	152	152	116	80	80
104	108	103	95	127	151	169	164	166	176
37	42	46	48	54	60	65	70	76	83
120	120	120	120	120	120	120	120	120	120
309	309	225	225	225	225	225	141	141	141
405	405	405	405	405	405	405	405	405	405
10	10	10	10	10	10	10	10	10	10
1,190	**1,202**	**1,119**	**1,117**	**1,141**	**1,173**	**1,200**	**1,082**	**1,058**	**1,077**

0.68%	**0.68%**	**0.62%**	**0.62%**	**0.62%**	**0.64%**	**0.65%**	**0.58%**	**0.56%**	**0.57%**
276	270	316	1,246	1,223	1,192	1,157	1,203	1,197	1,169
226	221	258	1,019	1,001	975	947	985	979	956
501	**492**	**574**	**2,265**	**2,224**	**2,167**	**2,105**	**2,188**	**2,177**	**2,125**
1,691	**1,693**	**1,693**	**3,382**	**3,365**	**3,340**	**3,305**	**3,270**	**3,235**	**3,202**
1%	1%	1%	2%	2%	2%	2%	2%	2%	2%
1,691	**1,693**	**1,693**	**3,382**	**3,365**	**3,340**	**3,305**	**3,270**	**3,235**	**3,202**
0.3%	0.3%	0.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%
501	**492**	**574**	**2,265**	**2,224**	**2,167**	**2,105**	**2,188**	**2,177**	**2,125**

B.2. Carbon Dioxide Emissions Reductions

To estimate annual regional emissions reductions, we first took data on projected electricity generation and carbon dioxide emissions over the 2008-2025 period for the East Central Area Reliability Coordination Agreement (ECARC) region as reported by the *Annual Energy Outlook* (EIA 2007c). We then calculated an *output emission rate*, defined as the ratio of emissions (lbs) to electricity generation (MWh). Using data from the Emissions and Generation Resource Integrated Database (eGRID) on subregional emissions rates and converting to standard tons (EPA 2007a), we calculated a *net marginal emissions factor* (ton/MWh), which is our *output emissions rate* multiplied by the ratio of marginal to average emissions rate. We then took out *emissions factor* and multiplied Ohio's estimated electricity savings (GWh) from the Policy Analysis in order to determine the regional *carbon dioxide emissions savings* for the 17-year period.

APPENDIX C – ENERGY EFFICIENCY RESOURCE ASSESSMENT

C.1. Residential Buildings

C.1.1. Overview of Approach

We analyzed thirty-six electricity efficiency measures for existing residential buildings, which are grouped by end-use (HVAC, water heating, refrigeration, appliances, lighting, furnace fans, and plug loads) and three measures for new residential buildings (see Table 25). For each measure, we estimated average measure lifetime, electricity savings (kWh) and costs per home upon replacement of the product or retrofitting of the measure. For a replacement-on-burnout measure,[59] the cost is the incremental cost of the efficient technology compared to the baseline technology. For retrofit measures, where existing equipment is not being replaced, such as improved insulation and infiltration reduction, the cost is the full installation cost of the measure. For measures modeled as replacement-on-burnout, the baseline is set according to the current market for that product, so the *baseline efficiency* is the minimum efficiency standard of that product. For measures modeled as retrofit, the baseline efficiency is that of estimated energy use in existing Ohio homes.

A measure is determined to be cost-effective if its levelized cost of saved energy, or cost of conserved energy (CCE), is less than $0.1101/kWh, the current average residential cost of electricity in Ohio (EIA 2008a). Estimated levelized costs for each efficiency measure, which assume a discount rate of 5%, are shown in Table 25. Equation one shows the calculation for cost of conserved energy.

Equation 1. *CCE = PMT ((Discount Rate), (Measure Lifetime), (Measure Cost)) / (Annual Savings per Measure (kWh))*

[59] In a replacement-on-burnout scenario, a consumer purchases the more efficient product at the time of replacement of that product.

Table 25. Residential Energy Efficiency Measure Characterizations

Measures	End-Use Category	Annual savings per household (kWh)	Cost of Saved Energy ($/kWh)	Pass Cost-Effective Test?	% Turnover	Adjustment Factor	Interaction Factor	% End Use Savings	Total Savings in 2025
Existing Building					**2025**		**2025**	**2025**	
Seal Ductwork	HVAC (load)	753	$ 0.0799	yes	85%	30%	100%	8%	1,013
Insulate Ductwork, R-8	HVAC (load)	602	$ 0.0318	yes	68%	43%	92%	7%	855
Infiltration reduction	HVAC (load)	753	$ 0.0128	yes	100%	44%	85%	12%	1,485
Insulation, ceiling, R-11 to R-38	HVAC (load)	703	$ 0.0077	yes	85%	28%	71%	5%	623
Insulation, ceiling, R-19 to R-38	HVAC (load)	314	$ 0.0172	yes	85%	41%	71%	3%	409
Blow-in wall insulation	HVAC (load)	1,129	$ 0.0140	yes	57%	15%	60%	2%	299
Estar Window, from single pane	HVAC (load)	3,794	$ 0.0077	yes	57%	15%	56%	7%	951
Estar Window, from double pane	HVAC (load)	596	$ 0.0491	yes	57%	55%	56%	4%	551
Cool Roof shingles	HVAC (load)	271	$ 0.0415	yes	85%	78%	36%	3%	339
HVAC Load Reducing Measures								**51%**	
Central HP (heating cycle); HSPF 9	HVAC (equip.)	2,823	$ 0.0303	yes	94%	5%	49%	2%	316
GSHP w/ desuperheater (14 EER)	HVAC (equip.)	2,530	$ 0.0812	yes	94%	1%	49%	0%	42
Central AC (cooling cycle) SEER 15	HVAC (equip.)	624	$ 0.0127	yes	94%	63%	49%	8%	975
ENERGY STAR Dehumidifier	HVAC (equip.)	213	$ 0.0159	yes	100%	6%	49%	0%	33
ENERGY STAR Room A/C (CEE Tier 2, 11.8 EER)	HVAC (equip.)	85	$ 0.0378	yes	100%	26%	49%	0%	57
Ceiling Fan (including light kit)	HVAC (equip.)	243	$ 0.0709	yes	100%	49%	49%	2%	310
HVAC Equipment Measures								**13%**	
TOTAL HVAC								**64%**	**8,259**
High-efficiency showerheads	Water Heating	234	$ 0.0127	yes	100%	60%	100%	17%	740
Faucet aerators	Water Heating	47	$ 0.0194	yes	100%	65%	100%	4%	160
Water heater pipe insulation	Water Heating	65	$ 0.0460	yes	100%	88%	100%	7%	302
H-axis clothes washer (2.0 MEF) (water heating)	Water Heating	232	$ 0.0640	yes	100%	65%	100%	19%	796
Dishwasher (Electric WH; 0.72 EF) (water heating)	Water Heating	37	$ 0.0647	yes	100%	85%	100%	4%	166
Efficient electric water heater (0.93 EF)	Water Heating	113	$ 0.0625	yes	100%	7%	53%	1%	23
Heat pump water heater (COP = 2.0)	Water Heating	2,103	$ 0.0427	yes	100%	12%	53%	16%	676
Water Heating Savings								**68%**	**2,864**
Refrigerator (20%)	Refrigeration	114	$ 0.0465	yes	89%	75%	100%	7%	404

Measures	End-Use Category	Annual savings per household (kWh)	Cost of Saved Energy ($/kWh)	Pass Cost-Effective Test?	% Turnover	Adjustment Factor	Interaction Factor	% End Use Savings	Total Savings in 2025
Refrigerator (25%)	Refrigeration	29	$ 0.0929	yes	89%	98%	100%	2%	132
Refrigeration Savings								**9%**	**536**
CFL, Advanced Incandescent Replacements	Lighting	1,005	$ (0.0032)	yes	100%	90%	100%	58%	4,774
Lighting Savings								**58%**	**4,774**
H-axis clothes washer (2.0 MEF)	Appliances	26	$ 0.0774	yes	100%	65%	100%	3%	89
Dishwasher (Electric WH; 0.68 EF)	Appliances	11	$ 0.0761	yes	100%	85%	100%	1%	49
Appliances Savings								**4%**	**139**
Efficient Furnace Fan (Heating Season)	Furnace Fans	367	$ 0.0473	yes	100%	67%	100%	41%	1,299
Efficient Furnace Fan (Cooling Season)	Furnace Fans	182	$ 0.0471	yes	100%	67%	100%	20%	646
Furnace Fan Savings								**61%**	**1,945**
ENERGY STAR Version 3.0 Television Spec.	Plug Loads	52	$ 0.0947	yes	100%	74%	100%	1%	50
Set-Top Box Power Reduction	Plug Loads	120	$ 0.0293	yes	100%	58%	100%	3%	90
1-watt standby power	Plug Loads	264	$ 0.0196	yes	100%	66%	100%	7%	920
Total Plug Load Savings								**11%**	**1,060**
In-home energy feedback monitor	All	525	$ 0.0573	yes	100%	79%	66%	3%	1,460
New Construction Building Measures									
New home 15% better than code (ENERGY STAR home)	New Construction	1,172	$ 0.0447	yes	100%	17%	100%	2%	66
New home 30% better than code (Proposed Building Code)	New Construction	2,345	$ 0.0411	yes	100%	35%	100%	8%	301
New home 50% better than code (Tax-credit-eligible)	New Construction	3,908	$ 0.0462	yes	100%	47%	100%	18%	669
New Homes Subtotal									**1,036**

C.1.2. Existing Buildings

To estimate the efficiency resource potential in existing homes in Ohio by 2025, we first adjusted individual measure savings by an *Adjustment Factor*. This factor accounts for the technical feasibility of efficiency measures (the percent of Ohio homes that satisfy the base case conditions and other technical prerequisites such as number of household members, heating fuel type, etc.) and the current market share of products that already meet the efficiency criteria. These assumptions are made explicit in Table 25.

We then adjusted savings from the improved building envelope (insulation, windows, infiltration reduction, and duct sealing) to account for the reduced heating and cooling loads imparted by each of the envelope measures. Then we adjusted HVAC equipment savings to account for savings already realized from the reduced loads. Similarly, we adjusted water heating equipment savings to account for reduced water heating loads from the use of more efficient clothes washers, low-flow shower heads, water heater pipe insulation, and faucet aerators. The multiplier for these adjustments is called the *Interaction Factor*.

We then adjusted replacement measures with lifetimes more than 17 years to only account for the percent turning over in 17 years, which represents the time period of the analysis. Note that the multiplier, *Percent Turnover,* is only applicable to products being replaced upon burnout and not retrofit measures such as insulation and duct sealing and testing. These retrofit measures therefore have 100% of measures "turning over."

Equation 2 shows our calculation for efficiency resource potential, incorporating the three factors discussed above:

Equation 2. *Efficiency Resource Potential* = ∑ *(Annual Savings per Measure (kWh))* x *(Percent Turnover)* x *(Adjustment Factor)* x *(Interaction Factor)*

To calculate the efficiency resource potential savings by end-use in 2025, we present the savings as a percent of end-use electricity consumption (assuming current electricity consumption by end-use from AEO 2007). For the non-HVAC savings, we then multiply the "% savings" by projected residential electricity consumption for that end-use in 2025 to estimate the total savings potential in that year (see Equation 2). We assume that savings in the residential new construction sector cover projected new HVAC consumption, and therefore multiply the HVAC "% savings" by 2008 electricity consumption of this end use. See Equation 3 for a summary of how we derive the savings estimate for existing residential buildings.

Equation 3. *Efficiency Resource Potential by end-use in 2025 (GWh) = (% End-Use Savings)* x *(Electricity Consumption by sector in 2025* (GWh))*
* 2008 for HVAC

New Construction

We estimate savings from new construction in a similar manner as existing home measures. We looked at three levels of efficiency in new homes: 15%, 30%, and 50% better than current energy code. In estimating new home energy savings, we use a similar approach as building codes, which address HVAC consumption only. We estimated *% Applicable* by allocating each home into one of the three bins, with 15% predominating the early years and 50% the later years. See Equation four for a summary of how we calculate savings in new construction.

Equation 4. *Efficiency Resource Potential in 2025 (GWh) = (% HVAC savings per home) x (Percent Applicable) x (Projected new HVAC consumption between 2008 and 2025 (GWh))*

C.1.3. Efficiency Measures

In-home energy feedback monitor

Measure Description: A device installed inside the home that communicates with the electric meter and displays real-time electricity use information to occupants.

Basecase: Average metered home with no feedback mechanism other than monthly utility bills

Data Explanation: Total households applicable (80%) from RECS 2005 (EIA 2008). Baseline electricity consumption is for an average household excluding multifamily buildings above four units from RECS (EIA 2008). Cost includes cost of product ($150) plus one hour of installation from Parker 2006. Percent savings (10%) from Stein 2004 and Hydro One 2006. Useful life (11 years) assumed to be similar to programmable thermostat, from ACEEE 2006. Penetration in residential sector technically achievable in all metered residential units.

Duct Sealing

Measure Description: Professional duct-sealing service suitable for retrofits and new construction, involving testing and either hand-applied or aerosol-based mastic (Jump 2006).

Basecase: Single-family home with a forced-air furnace and air conditioner.

Data Explanation: Baseline energy use from RECS (EIA 2008) depending on primary fuel use, plus a 25% adder representing high-use homes. Savings (10%) in each season (cooling and heating) is derived from 80% reduction in duct leakage (Jump 1996), which comprises half of the 20% of total HVAC energy use that can be associated with duct-related energy losses (the other half being by conduction [Hammurlund 1992; Proctor 1993]). A cost of $750 is mature-market cost of Aeroseal, from Bourne et al 1999. Applies to top 50% of residential homes with forced-air systems. Measure life is 20 years (SWEEP 2002)

Duct Insulation

Measure Description: R8 insulation applied to exposed ductwork in unconditioned spaces.

Basecase: Single-family home with a forced-air furnace and air conditioner with uninsulated ductwork passing through un-conditioned space (attic, un-finished basement, garage)

Data Explanation: Baseline energy use from RECS 2005 (EIA 2008) depending on primary fuel use, plus a 25% adder representing high-use homes. Savings from SWEEP, based on 10% heating/cooling energy use in forced-air system associated with conductive duct losses. Cost are $0.15–$0.20 per square foot of floor area. Floor area (1800 sq. ft) based off average floor area of colonial and ranch single family detached from ACEEE 1994. Applies to top 50% of residential homes with forced-air systems. Useful life is 25 years (SWEEP 2002).

Blower-Door Aided Infiltration Reduction

Measure Description: Application of foam and/or caulk around leakage areas applied and tested by a professional using a blower-door.

Basecase: Household with higher-than average heating and cooling energy use.

Data Explanation: Baseline energy use from RECS (EIA 2008) depending on primary fuel use, plus a 25% adder representing high-use homes. Savings of 10% from MT Screening Reports. Cost of $0.46/s.f. from XENERGY 2001. Useful life of 10 years from SWEEP 2002. Savings applied to percentage of homes that report drafts (44%), from RECS (EIA 2008).

Attic Insulation

Measure Description: Add insulation in attic floor to R-38.

Basecase: R-11assumed for houses reported to be "well insulated."

Data Explanation: Savings average of colonial and ranch savings for R11-R30 attic insulation from NYSERDA 1994, increased by multiplier (1.09) to incorporate savings from upgrading to R38. Total households applicable (28%) average from RECS 2008 for house that are "well insulated" and houses that are "not well insulated" (EIA 2008). Baseline energy use from RECS 2005 (EIA 2008) depending on primary fuel use, plus a 25% adder representing high-use homes. Cost of $0.70/s.f. from DEER database (CEC 2005a). Assumes 1000 s.f. of insulation needed. Useful measure life of 20 years from NYSERDA (2003).

Attic Insulation

Measure Description: Add insulation in attic floor to R-38.

Basecase: R-19 assumed for houses reported to be "well insulated."

Data Explanation: Savings average of colonial and ranch savings for R19-R30 attic insulation from NYSERDA 1994, increased by multiplier (1.34) to incorporate savings from upgrading to R38. Total households applicable (41%) from RECS 2008 for house that are "well insulated" (EIA 2008). Baseline energy use from RECS 2005 (EIA 2008) depending on primary fuel use, plus a 25% adder representing high-use homes. Cost of $0.70/s.f. from DEER database (CEC 2005a). Assumes 1000 s.f. of insulation needed. Useful measure life of 20 years from NYSERDA 2003.

Blow-in Cellulose Wall Insulation
Measure Description: Add blow-in cellulose insulation to un-insulated wall cavities

Basecase: Average-sized single-family home with wood-frame construction built before 1970.

Data Explanation: Total households applicable (15%) from RECS 2008 for houses that are "not well insulated" (EIA 2008). Baseline energy use from RECS 2005 (EIA 2008), depending on primary fuel use, plus a 25% adder representing high-use homes. Savings of 15% and 1700 s.f. of uninsulated wall space are based on average of colonial and ranch single-family detached house types from 1994 ACEEE study on Gas EE opportunities in Long Island. Cost of $1.32/s.f. (unit and installation cost) from DEER database (CEC 2005a). Useful measure life of 30 years from NYSERDA 2003.

Cool Roof Shingles
Measure Description: Roof shingles that meet ENERGY STAR residential requirements for reflectivity and thermal emittance due to light color or other material properties.

Basecase: Standard high-pitched residential roof with dark asphalt shingles

Data Explanation: Baseline electricity reflects cooling load only, from RECS 2005 (EIA 2008). Savings of 20% of cooling load and cost ($.10/s.f.) are from ACEEE Emerging Technologies analysis (Sachs et al 2004). Roof area (1400 sq. ft) based off assumption of 1000 sq. ft for attic area, multiplied by 1.4 (roof area generally 1.4 times greater than the area of the attic). Percent of homes applicable (86%) are the percent of households with asphalt shingles, from Dejarlais 2006 presentation (CEE Cool Roofs workshop). Market share (10%) and measure life (20 years) are from Sanchez et al. 2007.

ENERGY STAR Windows

Measure Description: Window replacements that meet regional ENERGY STAR requirements for U value and solar heat gain coefficient (SHGC).

Basecase: Replacement of 20 *single-pane* windows measuring approximately 15 s.f. each.

Data Explanation: Baseline energy use from RECS 2005 (EIA 2008). Savings (36%) from ratio of U-values associated with upgrading from single pane (U-value = 1.10) to ENERGY STAR (U-value = .40), from Lekcie et al. 1981. Number of units (20) from ACEEE 2006. Incremental cost assumes 300 sq. ft. of windows at $1.50 per sq. ft. (NEEP 2006). Measure life (30) from SWEEP 2002. Percent of applicable households (50%) based on ENERGY STAR market share data.

ENERGY STAR Windows

Measure Description: Window replacements that meet regional ENERGY STAR requirements for U value and solar heat gain coefficient (SHGC).

Basecase: Replacement of 20 *double-pane* windows measuring approximately 15 s.f. each.

Data Explanation: Baseline energy use from RECS 2005 (EIA 2008). Savings (9%) from ratio of U-values associated with upgrading from double pane (U-value = .49) to ENERGY STAR (U-value = .40), from Lekcie et al. 1981. Number of units (20) from ACEEE 2006. Incremental cost assumes 300 sq. ft. of windows at $1.50 per sq. ft. (NEEP 2006).

Measure life (30) from SWEEP 2002. Percent of applicable households (50%) based on ENERGY STAR market share data.

High-efficiency Central Air Conditioner (cooling only)
Measure Description: SEER 15

Basecase: Current federal standard: SEER 13

Data Explanation: Baseline consumption from RECS 2005 (EIA 2008). Percent savings (27%) and incremental cost from ENERGY STAR calculator for Central Air Conditioners using Columbus, OH, as a proxy. Assumed not to be used in conjunction with programmable thermostat. Market share (9%) from Sanchez et al. 2007, assumed to be half of market share for ENERGY STAR qualified unit with SEER = 15. Percent applicable (64%) equivalent to households with central AC, with and w/o heat pump (EIA 2003). Measure life (18 years) from DOE TSD (DOE 2001).

High-efficiency Heat Pump (heating only)
Measure Description: HSPF 9

Basecase: Current federal standard: HSPF 7.7

Data Explanation: Baseline consumption from RECS 2005 (EIA 2008). Percent savings (22%) and incremental cost ($1000) from ENERGY STAR calculator for Air-Source Heat Pumps using Richmond, VA, as a proxy and apportioned based on heating hours for Richmond, VA. Assumed not to be used in conjunction with programmable thermostat. Market share (11%) from Sanchez et al. 2007, assumed to be half of market share for ENERGY STAR qualified unit with HSPF = 8.2. Measure life (18 years) from DOE TSD (DOE 2001).

Efficient Furnace Fan (heating season)
Measure Description: High efficiency, ECM fan

Basecase: PSC fan

Data Explanation: Baseline electricity consumption from Lutz (2004), accounting for parasitics and adjusted by ratio of national to state HDD. Percent applicable (75%) equivalent to sum of households with forced air systems (EIA 2008). Electricity savings (425 kWh, 41%) from Pigg (2003) and adjusted by ratio of national to state HDD. Incremental costs ($200) from Sachs & Smith 2004, apportioned by ratio of national to state CDD ($161), although report notes that incremental costs will drop to $25-$45 upon market maturity. Incremental costs apportioned for heating season from ratio of heating season savings to total annual savings.

Efficient Furnace Fan (cooling season)
Measure Description: High efficiency, ECM fan

Basecase: PSC fan

Data Explanation: Baseline electricity consumption from Lutz (2004), accounting for parasitics and adjusted by ratio of national to state CDD. Percent applicable (58%) equivalent to sum of households with forced air systems (EIA 2003). Electricity savings (103 kWh, 21%) from Pigg (2008) and adjusted by ratio of national to state CDD ($39). Incremental costs ($200) from Sachs & Smith 2004, apportioned by ratio of seasonal savings, although report notes that incremental costs will drop to $25-$45 upon market maturity. Incremental costs apportioned for cooling season from ratio of cooling season savings to total annual savings.

Ground-Source Heat Pump
Measure Description: Closed ground-source heat pump with EER 14.

Basecase: Conventional air-source heat pump of SEER 13, HSPF 7.7

Data Explanation: Baseline energy use (for homes with electricity as primary fuel multiplied by 2 for high-use homes) and market penetration (of heat pumps) from RECS 2001(EIA 2003). New measure savings (21%) and cost ($2400) from ACEEE Emerging Technologies analysis (Sachs 2007). Analysis assumes technical feasibility in 10% of houses with forced-air electric heat (0.3%). Measure life (18 years) from Sachs 2007.

Ground-Source Heat Pump with Desuperheater (space heating)
Measure Description: HSPF 14

Basecase: Current federal standard: HSPF 7.7

Data Explanation: Total households applicable 1% (10% of house with electric heat and ducts) from RECS 2005 (EIA 2008). New measure savings (21%) and cost ($1,000 per ton) from ACEEE Emerging Technologies analysis (Sachs 2007). Analysis assumes technical feasibility in 10% of houses with electric forced-air heat (0.3%). Measure life (18 years) from Sachs 2007.

Ground-Source Heat Pump with Desuperheater (water heating only)
Measure Description: HSPF 9

Basecase: Current federal standard: HSPF 7.7

Data Explanation: Baseline energy use and market penetration (of heat pumps) from RECS 2005 (EIA 2008). New measure savings (25%) and cost ($1,000 per ton) from ACEEE Emerging Technologies analysis (Sachs 2007). Analysis assumes technical feasibility in 10% of houses with electric forced-air heat (0.3%). Measure life (18 years) from Sachs 2007.

Efficient Electric Storage Water Heater
Measure Description: 50-gallon electric storage water heater, 0.93 EF

Basecase: Current federal standard for typical, 50-gallon electric storage water heater, 0.90 EF

Data Explanation: Baseline consumption from GAMA water heater directory. Savings (3%) derived from EF increase. Incremental cost ($70) from Amann et al. 2007. Measure life (14 years) from NYSERDA 2003. Percent applicable (29%) equivalent to houses with electric water heaters (EIA 2003). Market share (36%) estimated based on percent of products on the market meeting EF 0.93 in the GAMA product database (GAMA 2007).

Heat Pump Water Heater
Measure Description: Either add-on or integrated heat-pump that uses the evaporation-compression cycle to extract heat from surrounding air to heat water in a conventional storage tank. COP 2.0 or above.

Basecase: Current federal standard for typical, 50-gallon electric storage water heater, 0.90 EF

Data Explanation: Baseline consumption from GAMA water heater directory. Percent applicable (10%) equivalent to households with electric water heaters multiplied by percentage of households that have three or more occupants (EIA 2008). Percent Savings (60%) and measure life (14.5 years) are from Sachs, et al 2004. Incremental cost ($910) based off electric heat pump with COP=2.2, from Amann et al. 2007 (Consumer Guide).

High-efficiency showerheads
Measure Description: 2.0 gallons per minute (gpm) showerhead

Basecase: Assumes electric water heater meeting current federal standard (see Electric Storage Water heater above). Showerhead meets federal requirements of 2.5 gpm

Data Explanation: Baseline consumption from RECS 2005 (EIA 2008) depending on primary water heating fuel. Savings (10%) from Brown et al. 1987. Cost estimate ($23) for a low-cost, basic model from the DEER database (CEC 2005a). Useful measure life of 9 years from Efficiency Vermont 2005. Percent of households applicable (29%) is percentage of households with electric water heating (EIA 2003).

Faucet Aerators
Measure Description: 1.5 gallons per minute (gpm) faucet aerator

Basecase: Assumes electric water heater meeting current federal standard (see Electric Storage Water heater above). Baseline aerator meets federal requirements of 2.5 gpm

Data Explanation: Baseline consumption from RECS 2005 (EIA 2008) depending on primary water heating fuel. Savings (2%) from Frontier Associates (2006). Cost estimate ($7) for a low-cost, basic model from the DEER database (CEC 2005a). Percent of homes applicable (29%) is percentage of households with electric water heating (EIA 2003).

Water Heater Pipe Insulation
Measure Description: Insulating 10 feet of exposed pipe in unconditioned space, ¾" thick.

Basecase: Assumes electric water heater meeting current federal standard (see Electric Storage Water heater above).

Data Explanation: Baseline consumption from RECS 2005 (EIA 2008) depending on primary water heating fuel. Savings estimate from CL&P 2007. Costs ($28) from DEER Database based off $0.37 per linear foot equipment cost and $2.44 per linear foot installation cost (CEC 2005a). Useful life of insulation 13 years from Efficiency Vermont 2005. Percent of homes applicable (29%) is percentage of households with electric water heating (EIA 2003).

Efficient Dehumidifier
Measure Description: Replacement dehumidifier that is ENERGY STAR certified based on the 2008 ENERGY STAR specification.

Basecase: Dehumidifier that meets current (2005) federal energy standards.

Data Explanation: Baseline and incremental costs ($150) and electricity consumption from ENERGY STAR calculator. Percent applicable (14%) equivalent to percent of households with a dehumidifier (EIA 2008). Percent savings (19%), measure life (12 years), and market share (60%) from Sanchez et al. 2007.

Efficient Room Air Conditioner
Measure Description: ENERGY STAR Room A/C (10000 Btu unit at 10.8 EER).

Basecase: Room A/C that meets 2000 federal energy standards (10000 Btu at 9.8 EER)

Data Explanation: Baseline consumption, savings, and incremental cost from ENERGY STAR savings calculator. Percent homes applicable (28%) based on number of units per home from RECS 2005 (EIA 2008). Measure life (13 years) from Sanchez et al. 2007. Market share (49%) from ENERGY STAR 2006 appliance sales data.

Refrigerator Tier I
Measure Description: Replacement refrigerator that meets 2008 ENERGY STAR requirements (20% better than federal standard)

Basecase: Refrigerator that meets current 2001 federal energy standards.

Data Explanation: Baseline consumption, incremental cost ($64) and measure life (19 years) from ACEEE analysis for PG&E/CA Title 24 (PG&E 2007). Market share (31%) from Sanchez et al. 2007.

Refrigerator Tier II
Measure Description: Replacement refrigerator that exceeds federal energy standard by 25% (CEE Tier 2)

Basecase: Refrigerator that meets current 2001 federal energy standards.

Data Explanation: Baseline consumption, incremental cost ($33) and measure life (19 years) from ACEEE analysis for PG&E/CA Title 24 (PG&E 2007).

Horizontal-Axis Clothes Washer (appliances)
Measure Description: Front-loading (H-axis) clothes washer meeting ENERGY STAR requirements (2.0 MEF)

Basecase: Federal standard for clothes washers: 1.26 MEF

Data Explanation: Savings (20%) from ENERGY STAR savings calculator, isolating appliance energy savings only. Incremental cost ($20) apportioned based on percentage of electricity consumption not dedicated to water heating. Percent of homes applicable (20%) based on appliance saturation data from RECS 2005 (EIA 2008). 2006 market share (33%) from EPA 2007c. Measure life (14 years) is from Sanchez et al. 2007.

Horizontal-Axis Clothes Washer (water heating)
Measure Description: Front-loading (H-axis) clothes washer meeting ENERGY STAR requirements (2.0 MEF)

Basecase: Federal standard for clothes washers: 1.26 MEF

Data Explanation: Savings (20%) from ENERGY STAR savings calculator, isolating water heating energy savings only. Incremental cost ($180) apportioned based on percentage of electricity consumption dedicated to water heating.

Percent of homes applicable (20%) based on appliance saturation data from RECS 2005 (EIA 2008). 2006 market share (33%) from EPA 2007c. Measure life (14 years) is from Sanchez et al. 2007.

Efficient Dishwasher (appliances)
Measure Description: Dishwasher meeting 2011 ENERGY STAR requirement of 0.72 EF

Basecase: Dishwasher meeting 2010 federal energy standard of 0.62 EF

Data Explanation: Incremental cost ($30) and electricity savings from DOE 2007 Technical Support Document, isolating appliance energy savings only. Percent applicable (55%) equivalent to households with a dishwasher. Incremental cost apportioned based off ratio of electricity savings between the appliance and electricity used for water heating. Measure life (13 years) is from Sanchez et al. 2007. Market share (15%) from April 2007 LBL analysis on the AHAM-efficiency advocate agreement.

Efficient Dishwasher (water heating)
Measure Description: Dishwasher meeting 2011 ENERGY STAR requirement of 0.72 EF

Basecase: Dishwasher meeting 2010 federal energy standard of 0.62 EF

Data Explanation: Incremental cost ($30) and energy savings from DOE 2007 Technical Support Document, isolating water heating energy savings only. Percent applicable (16%) equivalent to households with dishwasher and electric water heater. Incremental cost apportioned based off ratio of electricity savings between the appliance and electricity used for water heating. Measure life (13 years) is from Sanchez et al. 2007. Market share (15%) from April 2007 LBL analysis on the AHAM-efficiency advocate agreement.

Ceiling Fan
Measure Description: ENERGY STAR certified ceiling fan

Basecase: Standard ceiling fan as defined by ENERGY STAR

Data Explanation: Baseline consumption, new measure consumption, and incremental cost ($185) from ENERGY STAR calculator. 2.15 units per household assumed from RECS 2005. Percent applicable (74%) equivalent to number of households with a ceiling fan. Baseline and new measure consumption, as well as units per household, specific to East North Central region. Measure life (10 years) and market share (24%) are from Sanchez et al. 2007.

Compact Fluorescent Lighting
Measure Description: Savings from the 17-watt equivalent to baseline lamp (75%) applied to 80% of baseline incandescent lamp hours.

Basecase: Baseline house requires 25,659 incandescent lamp-hours per year; average incandescent wattage is 63 watts based on 2001 federal government lighting inventory survey (DOE 2002).

Data Explanation: Measure of 80% replacement by lamp-hours is ACEEE assumption based on a conservative estimate of feasible applications. Applies to all households. Market share (10%) from ACEEE estimate based on EPA's estimate of ENERGY STAR lamp sales in 2007 and ACEEE's estimate of total lamp sales.

Active Mode Efficiency for Televisions
Measure Description: ENERGY STAR Television Specification, Version 3.0

Basecase: Average of all TVs from ENERGY STAR data set (CEE 2008).

Data Explanation: Baseline consumption, new measure consumption, measure life (6 yrs), and savings from CEE 2008.

Low Power Set-Top Boxes
Measure Description: Require digital set-top boxes to have a maximum sleep state power level of 10 watts and to automatically enter sleep mode after 4 hours without user input.

Basecase: Typical house with 1.9 set top boxes.

Data Explanation: All data except cost is from Rainer (2008). No reliable incremental cost data is available. In the case of set-top boxes, efficiency measures are largely software-related, likely resulting in very low cost per kWh saved per household. Our cost estimate is set to result in a levelized cost similar to that for TVs.

One-Watt Standby for All Household Electronics
Measure Description: All new electronics devices required to have maximum "off" mode power level of 1 watt.

Basecase: Typical house with 17-20 devices.

Data Explanation: Baseline consumption, savings, incremental costs and measure life available from ACEEE 2004 emerging technologies analysis (Sachs et al. 2004). Penetration of new measure assumed by averaging market shares of all ENERGY STAR home electronics equipment.

ENERGY STAR New Home
Measure Description: New home that uses 15% less energy than code

Basecase: Code-compliant home (proposed 2008 IECC residential code revision)

Data Explanation: Baseline equals delivered HVAC and water heating energy use per household (across all households) from AEO (2007). Incremental costs ($805) and market share (5%) from personal communication with Shadid (2007). Percent applicable for new homes assume that 30% and 50% new buildings are phased-in one to two years prior to enactment of codes (30% in 2012 and 50% in 2020).

Advanced Building Code New Home
Measure Description: New home that uses 30% less energy than code

Basecase: Code-compliant home (proposed 2008 IECC residential code revision)

Data Explanation: Baseline equals delivered HVAC and water heating energy use per household (across all households) from AEO (2007). Incremental costs ($1480) and market share (0%) from personal communication with Shadid (2007). Percent applicable for new homes assume that 30% and 50% new buildings are phased-in one to two years prior to enactment of codes (30% in 2012 and 50% in 2020).

Tax-Credit-Eligible New Home
Measure Description: New home that uses 50% less energy than code.

Basecase: Code-compliant home (proposed 2008 IECC residential code revision)

Data Explanation: Baseline equals delivered HVAC and water heating energy use per household (across all households) from AEO (2007). Incremental costs ($2775) and market share (0%) from personal communication with Shadid (2007). Percent applicable for new homes assume that 30% and 50% new buildings are phased-in one to two years prior to enactment of codes (30% in 2012 and 50% in 2020).

C.2. Commercial Buildings

C.2.1. Baseline End-Use Electricity Consumption

To estimate the resource potential for efficiency in commercial buildings in Ohio, we first develop a disaggregate characterization of baseline electricity consumption in the state for current electricity use and a reference load forecast (see Table 27). Highly disaggregated commercial electricity consumption data is unfortunately not available at the state level. To estimate these data, we start with current electricity consumption for the Ohio commercial sector (EIA 2008) and a forecast out to 2025 based on PJM forecasts, and we disaggregate by end-use using average regional data from CBECS 2003 (EIA 2006b) and AEO 2007 (EIA 2007c).

Table 27. Baseline Commercial Electricity Consumption by End-Use (GWh)

End-Use	2009	%	2015	%	2025	%
Heating	1,746	4%	1,972	4%	2,070	3%
Cooling	5,286	11%	5,972	11%	6,738	10%
Ventilation	2,502	5%	2,826	5%	3,135	5%
HVAC subtotal	9,534	19%	10,770	19%	11,943	19%
Water Heating	1,350	3%	1,525	3%	1,565	2%
Refrigeration	2,927	6%	3,306	6%	3,639	6%
Lighting	17,628	36%	19,913	36%	22,178	34%
Office Equipment	7,055	14%	7,970	14%	10,253	16%
Other	10,533	21%	11,899	21%	14,932	23%
Total	**49,027**	**100%**	**55,383**	**100%**	**64,510**	**100%**

Next, we estimate commercial square footage in the state using electricity intensity data (kWh per square foot) by census region from CBECS (EIA 2006b). We use the East North Central region to estimate an overall electricity intensity for the state of Ohio of 13.8 kWh per square foot. Total electricity consumption in the state divided by the electricity intensity provides an estimate of commercial floorspace. Using this methodology, we estimate 3,553 million square feet of commercial floorspace in the state.

C.2.2. Measure Cost-Effectiveness

We then analyze 34 efficiency measures for existing commercial buildings and 3 new construction whole-building measures to examine the cost-effective energy efficiency resource potential. For each efficiency measure, we estimate electricity savings (*Annual Savings per Measure)* and incremental cost (*Measure Cost)* in a "replacement on burnout scenario," which assumes that the product is replaced or the measure is installed at the end of the measure's useful life. Savings and costs are incremental to an assumed *Baseline Measure*. We estimate savings (kWh) and costs ($) on a per-unit and/or a per-square foot commercial floorspace basis. For each measure we also assume a *Measure Lifetime*, or the estimated useful life of the product.

A measure is determined to be cost-effective if its levelized cost of saved energy, or cost of conserved energy (CCE), is less than $0.1015/kWh, the estimated current average commercial cost of electricity in Ohio. The estimated CCE for each efficiency measure, which assume a discount rate of 5%, are shown in the measure descriptions below. Equation 1 shows the calculation for cost of conserved energy.

Our assumed *Baseline Measure*, *Annual Savings per Measure, Measure Cost, Measure Lifetime, and CCE* are reported for each of the efficiency measures in the list of measure descriptions below. We group the 33 efficiency measures for existing commercial buildings by end-use and list the 3 new building measures last.

Equation 1. *CCE = PMT ((Discount Rate), (Measure Lifetime), (Measure Cost)) / (Annual Savings per Measure (kWh))*

C.2.3. Total Statewide Resource Potential

For each measure, we then derive *Annual Savings per Measure* on a per square foot basis *(kWh per square foot)* for the applicable end-use. For measures that we only have savings on a per-unit or per-building basis, we first derive the percent savings and multiply by the *Baseline Electricity Intensity* for that end-use. The assumed baseline intensities for each end use are shown in Table 28. As an example, for a specific lighting measure we multiply its percent savings by the baseline electricity intensity (kWh per square foot) for the lighting end-use.

Table 28. Commercial End-Use Baseline Electricity Intensities (kWh per s.f.)

End-Use	2009
Heating	0.5
Cooling	1.5
Ventilation	0.7
HVAC Subtotal	2.7
Water Heating	0.4
Cooking	0.1
Lighting	5.0
Refrigeration	0.8
Office Equipment	2.0
Other	2.8
Total	**13.8**

To estimate the total efficiency resource potential in existing commercial buildings in Ohio by 2025, we must first adjust the individual measure savings by an *Adjustment Factor* (See Equation 2). This factor accounts for two adjustments: the technical feasibility of efficiency measures, called the *Percent Applicable* (the percent of Ohio floorspace that satisfy the base case conditions and other technical prerequisites such as heating fuel type and cooling equipment, etc); and the *Current Market Share*, or the percent of products that already meet the efficiency criteria. These assumptions are outlined in each of the efficiency measure descriptions below.

Equation 2. *Adjustment Factor = Percent Applicable x (1-Current Market Share).*

We then adjust total savings for interactions among individual measures. For example, we must adjust HVAC equipment savings downward to account for savings already realized through improved building envelope measures (insulation and windows), which reduce heating and cooling loads. Similarly, we adjust water heating equipment savings to account for reduced water heating loads from the use of more efficient clothes washers. The multiplier for these adjustments is called the *Interaction Factor.*

Finally, we adjust replacement measures with lifetimes more than 7 and 17 years to only account for the percent turning over in 7 and 17 years, which represents the benchmark years of 2015 and 2025, respectively. Note that the multiplier, *Percent Turnover,* is only applicable to products being replaced upon burnout and not retrofit measures such as insulation. These retrofit measures therefore have 100% of measures "turning over."

We then calculate the resource potential for each measure in the state using Equation 3, which takes into account all of the adjustments described above. The sum of the resource potential from all measures is the overall energy efficiency resource potential in the state's commercial buildings sector.

Equation 3. *Efficiency Resource Potential in 2015 and 2025 (GWh) = (Annual Savings per Measure (kWh per square foot)) x (Commercial floor space in Ohio in millions of square feet) x (Percent Applicable)* x *(Interaction Factor) x (Percent Turnover)*

C.2.4. Efficiency Measures

Table 29 shows the thirty-eight efficiency measures examined for this analysis, grouped by end-use costs, savings (kWh) per product or square foot, *Percent Applicable, Interaction Factor, Percent Turnover,* and total savings potential (GWh) in 2025. Detailed descriptions of each measure are given below, grouped by end-use.

<u>**HVAC**</u>

1. Duct testing and sealing

Measure Description. Testing and sealing air distribution ducts saves energy. This measure assumes supply and return ducts will be fully sealed.

Basecase: The basecase assumes air loss of 29% of fan flow, and leakage of 15% of the system flow.

Data Explanation: Percent savings of 6% apply to whole-building electricity consumption (SWEEP 2002). An incremental cost of \$3,375, which assumes \$300 per ton, a 10 year lifetime, and 25% applicability are ACEEE estimates. The levelized cost is calculated to be 1.8 cents/kWh.

2. Cool roof

Measure Description: This measure involves installing a sun-reflective coating on the roof of a building with a flat top. This reduces air conditioning energy loads by reducing the solar energy absorbed by the roof.

Basecase: The baseline electricity intensity for HVAC end uses in Ohio (2.7 kWh/ft^2/year) is used as the basecase.

Data Explanation: We assume 4% HVAC load savings (ACEEE 1997) off the baseline electricity intensity for HVAC end-uses in Ohio (CBECS 2003), an incremental cost of \$0.25 per ft^2 (SWEEP 2002), and a 20-year average lifetime (SWEEP 2002). Percent applicable (80%) is an ACEEE estimate. Savings and cost per unit are based on a 15,000 ft^2 building from ACEEE Mid-Atlantic study (1997). The levelized cost is calculated to be 5.5 cents/kWh.

3. Roof insulation

Measure Description: Fiberglass or cellulose insulation material in roof cavities will reduce heat transfer, though the type of building construction limits insulation possibilities. R-values describe the performance factor for insulation levels.

Basecase: The basecase electricity intensity for this measure was disaggregated from the post-savings electricity intensity and the percentage of savings.

Data Explanation: We assume 3% savings and a post-savings electricity intensity of 0.28 kWh/ft^2/year, based on an average of four building types (ACEEE 1997). An average lifetime of 25 years (CL&P 2007) and an incremental cost of 12 cents/ft^2 were also assumed. The levelized cost is 30 cents/kWh.

4. Double Pane Low-Emissivity Windows

Measure Description: Double-pane windows have insulating air- or gas-filled spaces between each pane, which resist heat flow. Low-emissivity (low-e) glass has a special surface coating to reduce heat transfer back through the window, and a window's R-value represents the amount of heat transfer back through a window. Low-e windows are particularly useful in climates with heavy cooling loads, because they can reflect anywhere from 40% to 70% of the heat that is normally transmitted through clear glass. The Solar Heat Gain Coefficient (SHGC) represents the fraction of solar energy transferred through a window. For example, a low-e window with a 0.4 SHGC keeps out 60% of the sun's heat.

Basecase: The basecase electricity intensity for this measure was disaggregated from the post-savings electricity intensity and the percent savings.

Data Explanation: Percent savings of 3% apply to whole-building electricity consumption (ACEEE 1997). Incremental costs assume \$2 per window (SWEEP 2002). A measure life of 25 years is from SWEEP 2002. Percent applicable is an ACEEE estimate. The levelized cost is calculated to be 2 cents/kWh.

5. Ventilation fans with Variable-Frequency Drive

Measure Description: Variable Frequency Drive (VFD) controls the speed of a motor by adjusting the frequency of incoming power. By controlling the speed of a motor, the output of the system can be matched to the requirements of the process, thereby improving efficiency.

Basecase: The basecase unit is a 50 hp fan with 60% load factor, 93% efficiency (ODP, EPAct levels) and 3653 operating hours/year (21-50 hp category from ACEEE standards savings analysis).

Data Explanation: We assume 25% savings applies to ventilation only (ACEEE 1997), which is a conservative estimate. We estimate a $6,650 incremental cost, which assumes $125/hp for VFD and $8/hp for a better fan, and a 10-year measure life (SWEEP 2002). ACEEE estimates that this measure can apply to 40% of systems. The levelized cost is calculated to be 3.9 cents/kWh.

6. High-Efficiency Unitary AC/HP
65,000 Btu — 135 Btu
135,000 Btu — 240,000 Btu

Measure Description: Unitary packaged air conditioners and heat pumps represent the heating, ventilating, and air conditioning (HVAC) equipment class with the greatest energy use in the commercial sector in the United States, and are used in approximately 48% of the cooled floor space in the commercial sector (DOE 2004). High efficiency units have a greater energy efficiency ratio (EER).

Basecase: The assumed basecase unit meets the 2010 federal efficiency standard. Baseline electricity intensity for this end-use,2.7 kWh per ft^2, is the estimated HVAC consumption in commercial buildings in Ohio. This is data from the East North Central region from EIA's commercial buildings survey (EIA 2006b).

Data Explanation: This measure includes two size ranges; the first is 65,000 Btu to 135,000 Btu, and the second is 135,000 Btu to 240,000 Btu. The measure assumes a 12 EER unit relative to the 2010 federal standard, which ranges from about 10.4 EER to 11.2 EER, depending on the unit type and size. The energy savings average 1,070 kWh (7.2%) for the smaller unit and 3,371 kWh (10.8%) for the larger unit. We assume a measure lifetime of 15 years (LBNL 2003). Incremental costs (average $629 for 65 kBtu to135 kBtu and $1,415 for 135 kBtu to 240 kBtu) are derived from DOE's Technical Support Document (DOE 2004). Percent applicable (33% for 65 kBtu to135 kBtu), and the percent of floorspace with cooling from unitary equipment are also from DOE's Technical Support Document (DOE 2004). The levelized cost is calculated to be 4–5.7 cents/kWh, depending on unit type and size.

7. High-Efficiency Packaged Terminal AC/HP

Measure Description: PTACs and PTHPs are self-contained heating and air-conditioning units encased inside a sleeve specifically designed to go through the exterior building wall. The basic design of a PTAC is comprised of a compressor, an evaporator, a condenser, a fan, and an enclosure. They are primarily used to provide space conditioning for commercial facilities such as hotels, hospitals, apartments, dormitories, schools, and offices. High-efficiency units have a higher energy efficiency ratio (EER) for cooling units and coefficient of performance (COP) for heat pumps.

Basecase: Consistent with all HVAC-related measures, the baseline electricity intensity is 2.7 kWh per ft^2, which is the estimated HVAC consumption in commercial buildings in Ohio. This is based on the East North Central region from EIA's commercial buildings survey (EIA 2006b).

Data Explanation: We assume that high efficiency units save an average of 7.8%, or 226 kWh per unit, relative to a basecase, which is based on an ACEEE submission to ASHRAE using web data. The measure life is 15 years (ASHRAE 90.1-1999). Percent applicable is 5%, which is the percent of cooling floorspace from packaged terminal units (ADL 2001). The levelized cost is calculated to be 3.8 cents/kWh.

8. Efficient Room Air Conditioner

Measure Description: An ENERGY STAR room AC must be at least a 10% improvement over the 2000 federal standard (an average 8000 Btu unit must have a 10.8 EER).

Basecase: The assumed basecase unit is a room A/C that meets 2000 federal energy standards (an average 8000 Btu unit has a 9.8 EER) and uses an average of 677 kWh per unit. Baseline electricity intensity for this end-use, 1.5 kWh per ft^2, is the estimated cooling consumption in commercial buildings in Ohio. This is based on the East North Central region from EIA's commercial buildings survey (EIA 2006).

Data Explanation: We assume an ENERGY STAR room AC uses 590 kWh per year, saves 9% of basecase energy, and has an incremental cost of $30 (ENERGY STAR calculator). We assume a measure life of 9 years (ENERGY STAR calculator), a current market share of 52% (EPA 2007c), and percent applicable assumes 4% of cooling floorspace uses room AC units (ADL 2001). The levelized cost is calculated to be 4.3 cents/kWh.

9. High-Efficiency Chiller

Measure Description: "Chillers" are the hearts of very large air-conditioning systems for buildings and campuses with central chilled water systems. A centrifugal chiller utilizes the vapor compression cycle to chill water and reject the heat collected from the chilled water plus the heat from the compressor to a second water loop controlled by a cooling tower.

Basecase: The basecase unit assumes 0.634 kW/ton T24 from DEER for an average 150 ton system and 1,593 national average full-load operating hours from the ASHRAE 90.1-1999 analysis. Baseline electricity intensity for this end-use, 2.7 kWh per ft^2, is the estimated HVAC consumption in commercial buildings in Ohio. This is based on the East North Central region from EIA's commercial buildings survey (EIA 2006b).

Data Explanation: We assume the new measure has 20% savings, which is derived from estimates provided in SWEEP 2002 and ACEEE 1997. The lifetime estimate of 23 years is from the ASHRAE Handbook (HVAC Applications). Incremental costs are $9,900 and assume a 150 ton average unit (CEC 2005a). Percent applicable (33%) assumes percentage of cooling floorspace using chillers (ADL 2001). The levelized cost is calculated to be 2.4 cents/kWh.

10. Dual-Enthalpy Economizer

Measure Description: Economizers modulate the amount of outside air introduced into the ventilation system based on the relative temperature and humidity of the outside and return air. If the enthalpy, or the latent and sensible heat, of the outside air is less than that of the return air when space cooling is required, then the outside air is allowed to reduce or eliminate the cooling requirement of the AC equipment.

Basecase: Baseline electricity intensity, 1.5 kWh per ft^2, is the estimated cooling consumption in commercial buildings in Ohio. This is based on the East North Central region from EIA's commercial buildings survey (EIA 2006b).

Data Explanation: Savings per unit assume 276 kWh (20% savings) per ton for an average 11-ton unit (CL&P 2007). Average measure life is 10 years (CL&P 2007). Incremental costs per unit are from NYSERDA 2003. Percent applicable is the portion of cooling square footage represented by packaged AC and HP units, and assumes that 90% of these unitary systems could benefit from economizers (ACEEE estimate). It also assumes a 5% current market share (ACEEE estimate). The levelized cost is calculated to be 3.8 cents/kWh.

11. Demand-Controlled Ventilation

Measure Description: Often, HVAC systems are designed to supply ventilated air based on assumed occupancy levels, resulting in over-ventilation. Demand-controlled ventilation monitors CO_2 levels in different zones and delivers the required ventilation only when and where it is needed.

Basecase: The basecase is standard ventilation electricity consumption for a 50,000 ft^2 office building, or about 40,000 kWh/year (Sachs et al. 2004). Baseline electricity intensity for this end-use, 0.7 kWh per ft^2, is the estimated ventilation consumption in commercial buildings in Ohio. This is based on the East North Central region from EIA's commercial buildings survey (EIA 2006b).

Data Explanation: We assume 20% savings for this measure (ET 2004). Energy use per unit is 32,000 kWh/year, assuming a 50,000 ft^2 building (Sachs et al. 2004). The lifetime estimate is 15 years, and incremental costs are $3,450 (Sachs et al. 2004). The measure is applicable to 90% of larger (60%) cooling units (Sachs et al. 2004). The levelized cost is calculated to be 4.2 cents/kWh.

12. HVAC Tune-up

Measure Description: Most HVAC technicians lack interest, training, equipment and methods to perform quality refrigerant charge and airflow (RCA) tune-ups. Because many new and existing air conditioners have improper RCA, which reduces efficiency, there is significant potential for energy savings by diagnosing and correcting RCA.

Basecase: The assumed basecase unit is a 4.5 ton commercial unitary AC/HP per California program experience (CPUC 2006), estimated to use 8,396 annual kWh per the unitary AC/HP measure. The base electricity intensity for the HVAC end-use is 3.4 kWh/ ft^2, the average for small buildings less than 25,000 ft^2, for which this measure is applicable.

Data Explanation: We assume 11% savings from this measure according to California's DEER database (CEC 2005a) and the California Refrigerant and Air Charge (RCA) program report (CPUC 2006). We assume that 60% of units have improper RCA (CPUC 2006), and therefore this measure is applicable to 60% of unitary HVAC units in buildings less than or equal to 25,000 ft^2 (CBECS 2003; E N Central region). We estimate an average measure life of 3 years, as units need to be periodically re-tuned. We assume a cost of $158 for this measure, based on a $35/ton labor cost (CEC 2005a) and an assumed 4.5-ton unit. The levelized cost is calculated to be 6.3 cents/kWh.

13. Energy Management System (EMS)

Measure Description: An Energy Management System (EMS) is a computerized system that collects, analyzes and displays information on HVAC, lighting, refrigeration, and other commercial building subsystems to aid commercial building and facility energy managers, financial managers, and electric utilities in reducing energy use in buildings.

Basecase: Baseline electricity intensity is the average HVAC end-use consumption in Ohio, estimated from CBECS (EIA 2006b) to be the average of consumption in the East North Central region.

Data Explanation: We assume 10% cooling savings and 7.5% heating and ventilation savings from an installed EMS (NYSERDA 2003). We estimate a 15-year measure life for the system. We assume total incremental costs of $19,333 for a 60,000 ft^2 building, which is derived from NYSERDA 2003, and assume a third of this ($6,380) for this measure by assuming the cost is spread equally among electric HVAC, gas HVAC and lighting. Percent applicable is an ACEEE estimate. The levelized cost is calculated to be 5.8 cents/kWh.

13. Retrocommissioning

Measure Description: Commercial building performance tends to degrade over time, and many new buildings do not perform as designed, requiring periodic upgrades to restore system functions to optimal performance. Retrocommissioning (RCx) is a systematic process to optimize building performance through O&M tune-up activities and diagnostic testing to identify problems in mechanical systems, controls, and lighting. The best candidates for RCx are buildings over 50,000 or 100,000 ft2.

Basecase: The baseline is electricity intensity for HVAC and lighting end-uses in buildings greater than 50,000 ft2 (8 kWh/ ft2), which is based on data from CBECS (EIA 2006b). We take the average of the East North Central region to estimate electricity intensity in Ohio buildings.

Data Explanation: We assume 10% savings for HVAC and lighting end-uses (Sachs et al. 2004) in all commercial floorspace for buildings greater than 100,000 ft2, and 50% of floorspace in buildings 50,000 ft2 or greater based on data from CBECS (EIA 2006b). Xcel Energy's RCx program results estimate an average RCx useful life of 7 years (Xcel Energy 2006). We assume a $0.25 cost per ft2 (Sachs et al. 2004). The levelized cost is calculated to be 5.4 cents/kWh.

Water Heating Measures

14. Heat Pump Water Heater

Measure Description: A heat pump water heater uses electricity to move heat from one place to another, rather than a less efficient electric resistance water heater which uses electricity to generate the heat directly. The heat source is the outside air or air in the basement where the unit is located.

Basecase: The basecase is standard electric water heating, with electricity consumption of 22,831 kWh/year (derived from energy savings and percent savings). Baseline electricity intensity for this end-use, 0.38 kWh per ft^2, is the estimated water heating consumption in commercial buildings in Ohio. This is based on the East North Central region from EIA's commercial buildings survey.

Data Explanation: We assumed a 62% savings, based on a simple coefficient of performance ratio. The assumed 14,155 kWh savings, $4,067 incremental cost, and 12 year lifetime estimates are from NYSERDA 2003. Percent applicable is based on engineering estimates for NYSERDA 2003, which assumes the measure is applicable to 70% of food service floorspace and 30% of lodging, education, and health care floorspace. Percent applicable is then multiplied by 2, since these building types are more energy and hot-water intensive than the average commercial building. The levelized cost is calculated to be 3.2 cents/kWh.

15. Efficient Commercial Clothes Washer (water heating portion)

Measure Description: A high-efficiency commercial clothes washer saves both energy and water, and as a result reduces water heating loads. For a high-efficiency clothes washer, we assume a unit with an MEF of 2.0, which represents about 80% of products on ENERGY STAR's product lists.

Basecase: The basecase unit is a clothes washer that meets DOE's federal efficiency standard of 1.26 MEF. An average unit consumes 1,136 kWh annually for water heating, which is derived from DOE 2007. Baseline electricity intensity for this end-use is 0.38 kWh/ft^2/year (water heating portion only).

Data Explanation: Savings on electric water heating from this measure assume a 2.0 MEF clothes washer uses an average 431 kWh annually, for a 62% savings, which is derived from DOE's TSD (DOE 2007). We assume the measure is applicable to the 17% of units that have electric water heating, and assume a 20% market share of efficient products. The overall stock estimate is based on national stock data (DOE 2007) and prorated to Ohio based on commercial building floorspace. We assume an incremental cost for an efficient unit is $316 and an 11-year measure life (DOE 2007). The levelized cost is calculated to be 3.2 cents/kWh.

Refrigeration Measures

16. Efficient Walk-In Refrigerators & Freezers

Measure Description: Walk-in refrigerators and freezers (walk-ins) are medium and low-temperature refrigerated spaces that can be walked into, and that are used to maintain the temperature of pre-cooled materials (not to rapidly cool down materials from warmer temperatures). A high-efficiency walk-in is defined as meeting the 2004 CEC standard for walk-ins. This includes prescriptive requirements such as higher levels of insulation, motor types, and the use of automatic door-closers (Nadel et al. 2006).

Basecase: The baseline energy use for an average walk-in is 18,859 kWh/year (Nadel et al. 2006). Baseline electricity intensity for this end-use, 0.82 kWh per ft^2, is the estimated refrigeration energy consumption in commercial buildings in Ohio. This is based on the East North Central region from EIA's commercial buildings survey.

Data Explanation: For a high-efficiency walk-in unit, we assume 44% savings over a baseline unit, or 8220 kWh/year, $957 incremental cost, and a 12 year measure lifetime (Nadel et al. 2006), which are based on a PG&E CASE study (2005). We estimate percent applicable as the 18% of refrigeration energy use attributed to walk-ins (ADL 2006) and estimate a 50% current market share of high-efficiency products (ACEEE estimate). The levelized cost is calculated to be 1.3 cents/kWh.

17. Efficient Reach-In Coolers & Freezers

Measure Description: This measure includes high-efficiency packaged commercial reach-in refrigerators and freezers with solid doors, and refrigerators with transparent doors such as beverage merchandisers. High-efficiency units are those that meet the CEE Tier 2 performance standard, as estimated in PG&E 2005.

Basecase: We assume a baseline unit, which is one that meets that upcoming (2009 or 2010) federal standard, uses 4,027 kWh per year. This is weighted by sales of unit type per PG&E 2004. Baseline electricity intensity for this end-use, 0.82 kWh per ft^2, is the estimated refrigeration energy consumption in commercial buildings in Ohio. This is based on the East North Central region from EIA's commercial buildings survey.

Data Explanation: The savings estimate for a high-efficiency unit, 31% savings or 1,268 kWh per year, is a weighted average of different types of reach-ins that meet CEE's Tier 2 performance standard (PG&E 2005). We estimate an average lifetime of 9 years and an incremental cost of $341, both per PG&E 2005. We estimate percent applicable as the percent of refrigeration energy use attributed to reach-ins and beverage merchandisers, or 17% (ADL 2006), and assume a 10% current market share of high-efficiency products per PG&E 2005. The levelized cost is calculated to be 2.0 cents/kWh.

18. Efficient Ice-Maker

Measure Description: Commercial ice makers, which are used in hospitals, hotels, and food service and preservation, have energy savings potential largely in their refrigeration systems. We assume an efficient icemaker meets CEC's Tier 2 level of energy savings, which incorporate improved compressors, heat exchangers, and controls, as well as better insulation and gaskets.

Basecase: The baseline energy use, 3,338 kWh per year, is a weighted average of different types of ice-makers that meet the 2010 standard. Baseline electricity intensity for this end-use, 0.82 kWh per ft^2, is the estimated refrigeration energy consumption in commercial buildings in Ohio. This is based on the East North Central region from EIA's commercial buildings survey.

Data Explanation: The 16% savings estimate for a high-efficiency unit, or 542 kWh per year, is a weighted average of different types of ice-makers that meet CEC's tier 2 energy savings (PG&E 2005). We estimate an average lifetime of 10 years and an incremental cost of $100, both per PG&E 2005. We estimate percent applicable as the percent of refrigeration energy use attributed to ice-makers, or 10% (ADL 2006), and assume a 10% current market share of high-efficiency products per PG&E 2005 and ACEEE judgment. The levelized cost is calculated to be 2.4 cents/kWh.

19. Efficient Built-up Refrigeration System

Measure Description: Built-up or supermarket refrigeration systems are primarily made up of refrigerated display cases for holding food for self-service shopping, as well as machine room cooling technologies. More efficient built-up systems include improved machine room technologies (evaporative condensers, mechanical sub-cooling, and heat reclaim), high-efficiency evaporative fan motors, hot gas defrost, liquid-suction heat exchangers, antisweat control, and defrost control.

Basecase: The measure baseline is 1,600,000 kWh for a 45,000 ft^2 supermarket with a built-up refrigeration system. Baseline electricity intensity for this end-use, 0.82 kWh per ft^2, is the estimated refrigeration energy consumption in commercial buildings in Ohio. This is based on the East North Central region from EIA's commercial buildings survey.

Data Explanation: Per-unit savings of 336,000 kWh (21%) are from ADL 1996 and assume an average new 45,000 ft^2 supermarket with a 5-year payback. We estimate percent applicable as the percent of refrigeration energy use attributed to built-up refrigeration, or 33% (ADL 1996). Incremental cost ($37,000) and lifetime (10 years) are from ADL 1996. The levelized cost is calculated to be 1.4 cents/kWh.

20. Efficient Vending Machine

Measure Description: ENERGY STAR vending machines must consume 50% less energy than standard machines. Under the Tier II ENERGY STAR level, this translates to a maximum energy consumption of 6.53 kWh/day for a 650-can machine.

Basecase: A Tier I ENERGY STAR level vending machine is assumed to be the basecase. On average, it uses 2,816 kWh per year (ENERGY STAR calculator for a 600 can machine). Baseline electricity intensity for this end-use, 0.82 kWh per ft^2, is the estimated refrigeration energy consumption in commercial buildings in Ohio. This is based on the East North Central region from EIA's commercial buildings survey.

Data Explanation: Per unit savings of 18% (509 kWh/year) are estimated from ASAP 2007 based on ENERGY STAR calculator estimates. Likewise, an incremental cost of $30, and a lifetime estimate of 10 years are from ASAP 2007. We estimate percent applicable as the percent of refrigeration energy use attributed to built-up refrigeration, or 13% (NYSERDA 2003). Stock estimates are from the 2005 TSD (DOE 2005). The levelized cost is calculated to be 0.8 cents/kWh.

21. Vending Miser

Measure Description: A Vending Miser is an energy control device for refrigerated vending machines. Using an occupancy sensor, the control turns off the machine's lights and duty cycles the compressor based on ambient air temperature.

Basecase: The basecase unit is an efficient vending machine that meets the ENERGY STAR tier II level and uses 2,309 kWh per year (ENERGY STAR calculator for a 600 can machine). Baseline electricity intensity is for the refrigeration end-use (0.82 kWh/ ft^2).

Data Explanation: We assume 35% savings for this measure based on manufacturer data (usatech.com 2008), an incremental cost of $167 (NYSERDA 2003), and a measure life of 10 years (NYSERDA 2003). The levelized cost is calculated to be 2.7 cents/kWh.

Appliances

22. Efficient Hot Food Holding Cabinets

Measure Description: Commercial hot food holding cabinets are used in the commercial kitchen industry primarily for keeping food at safe serving temperature, without drying it out or further cooking it. These cabinets can also be used to keep plates warm and to transport food for catering events. High efficiency models differ mainly in that they are better insulated.

Basecase: The basecase unit is an uninsulated cabinet that consumes 5,190 kWh per year. This was calculated from CASE (2004) using a simple average of three sizes of cabinets, and then weighting the average using CASE figures for insulated cabinets.

Data Explanation: The energy savings from an insulated holding cabinet are 1,815 kWh per year (35% savings), with an incremental cost of $453, and an estimated 15 year lifetime (ASAP 2007, based on PG&E CASE study (2004)). Percent applicable refers to the 25% of holding cabinets that are currently uninsulated (ASAP 2007, based on PG&E CASE study (2004)). The levelized cost is calculated to be 2.4 cents/kWh.

23. Efficient Commercial Clothes Washer (excluding hot water energy)

Measure Description: A high-efficiency commercial clothes washer saves both energy and water. For a high-efficiency clothes washer, we assume a unit with an MEF of 2.0, which represent about 80% of products on ENERGY STAR's product lists.

Basecase: The basecase unit is a clothes washer that meets DOE's federal efficiency standard of 1.26 MEF. An average unit consumes 1,530 kWh annually for non-water heating uses, which is derived from DOE 2007.

Data Explanation: Electric savings from this measure assume a 2.0 MEF clothes washer uses an average 1,191 kWh annually, for a 22% savings, which is derived from DOE's TSD (DOE 2007). We assume the measure is applicable to the 39% of units that have electric dryer heating (removal of moisture from clothes), and assume a 20% market share of efficient products. The overall stock estimate is based on national stock data (DOE 2007) and prorated to Ohio based on commercial building floorspace. We assume an incremental cost for an efficient unit is $316 and an 11-year measure life (DOE 2007). The levelized cost is calculated to be 3.7 cents/kWh.

Lighting Measures

24. Fluorescent Lighting Improvements

Measure Description: The new measure assumes extra-efficient ballasts and high-lumen lamps are installed with no change in light level (low ballast factor).

Basecase: Basecase watts per square foot reflects current installed fixtures. This includes 84,000 annual tube fluorescent kWh used per average 14,000 ft^2 commercial building (Navigant 2002). On average, fluorescent lights are operated 9.7 hours/day. We assume 2-lamp standard T8 fixtures and electronic ballasts as the baseline, plus a small number of existing 3-lamp T12 fixtures with magnetic ballasts that are not likely to be replaced in the absence of programs over the time horizon.

Data Explanation: We assume a percent savings of 27%.The incremental costs are $2 extra per ballast, and $1 extra for each of 2 lamps. The percent applicable (56%) is the fluorescent percent of total commercial lighting kWh (Navigant 2002). The levelized cost is calculated to be 0.7 cents/kWh.

25. HID Lighting Improvements

Measure Description: Metal halide lamps produce light by passing an electric arc through a mixture of gases. Efficiency improvements in metal halide lamps include pulse start lamp technology, electronic ballasts, and improved fixtures.

Basecase: Same basecase as #27 (Fluorescent lighting improvements).

Data Explanation: The new measure savings and costs are from a PG&E CASE study on Metal Halide Lamps & Fixtures (PG&E 2004). Energy savings were 447 kWh per year (26%), and incremental costs were $60. Percent applicable (12%) is the percentage of commercial electricity use for lighting that comes from HIDs (Navigant 2002). The levelized cost is calculated to be 6.3 cents/kWh.

26. Replace Incandescent Lamps

Measure Description: The new measure assumes that 4 average 75 W incandescent lamps are replaced with 23 W CFLs. It is assumed that the lights operate 9.5 hours per day.

Basecase: Same basecase as #27 (Fluorescent lighting improvements).

Data Explanation: Energy savings are 180 kWh per year, or 69%. Incremental costs include $10 in the cost of 4 CFLs, but save $32 in labor for replacing the bulbs, so the result is a cost savings. Percent applicable assumes that 32% of commercial electricity use for lighting is from incandescents (Navigant 2002), and ACEEE estimates that 70% of sockets are applicable for the new measure. The levelized cost is calculated to be -1.3 cents/kWh.

27. Occupancy Sensor for Lighting

Measure Description: Installation of occupancy sensors can greatly reduce lighting energy demands in commercial spaces, by automatically turning off lights in unoccupied spaces.

Basecase: Same basecase as #27 (Fluorescent lighting improvements).

Data Explanation: Energy savings of 361 kWh per year (NYSERDA 2003) assumes 30% energy reduction in individual offices and rooms and 7.5% reduction in open spaces (ACEEE estimate). Incremental cost ($48) and lifetime (10 years) estimates are from NYSERDA 2003. Percent applicable (38%) is from ACEEE 2004. The levelized cost is calculated to be 1.7 cents/kWh.

28. Daylight Dimming System

Measure Description: A daylight dimming system automatically dims electric lights to take advantage (or "harvest") natural daylight.

Basecase: Same basecase as #27 (Fluorescent lighting improvements).

Data Explanation: Energy savings are estimated to be 143 kWh per year, or 35% (NYSERDA 2003). Savings apply for lamps on the perimeters of buildings (25% applicable – PIER 2003). Incremental cost ($68) and lifetime (20 years) estimates are from NYSERDA (2003). The levelized cost is calculated to be 3.8 cents/kWh.

29. Outdoor Lighting – Controls

Measure Description: This measure includes a variety of lighting control technologies for exterior lights.

Basecase: No basecase data was available for this measure.

Data Explanation: We assume a savings of 174 kWh, or 20%, from lighting controls. Incremental costs of $43 are from DEER 2001 and assume each control on average controls three fixtures. Percent applicable of 30% is an ACEEE estimate. The levelized cost is calculated to be 2.5 cents/kWh.

Miscellaneous

30. Office Equipment

Measure Description: This measure assumes a high-efficiency fax, printer, computer display, internal power supply, and a low mass copier.

Basecase: Baseline electricity use is 2886 kWh per year (NYSERDA 2003). Baseline electricity intensity for this end-use, 2.0 kWh per ft^2, is the estimated office equipment energy consumption in commercial buildings in Ohio. This is based on the East North Central region from EIA's commercial buildings survey.

Data Explanation: Energy savings were 1410 kWh per year (49%), lifetime was 5 years, and incremental costs were $20. Percent applicable is estimated to be (50%) (NYSERDA 2003). The levelized cost is calculated to be 0.3 cents/kWh.

31. Turn off appliances

Measure Description: This measure involves turning off, or putting into a low-power state: vending machines, computers, monitors, printers and copiers.

Basecase: Baseline electricity use is 1.1 kWh/ft2, based on data from CBECS, LBNL, and ENERGY STAR.

Data Explanation: Energy savings were 9114 kWh per year (40%), lifetime was 5 years, and incremental costs were $0. Percent applicable is 100%, as data for the savings already took into account the number of buildings that already shut down equipment after hours/. The levelized cost is $0/kWh

New Buildings

32. Efficient New Building (15% Savings)

Measure Description: Incorporating energy efficiency into building design is best achieved at the time of construction. New buildings can achieve major energy savings in heating and cooling, as well as energy-saving appliances.

Basecase: Basecase of 7.2 kWh per ft^2 is an estimate of HVAC, water heating, and lighting end-use electricity intensity for new buildings in Ohio, derived from data for buildings built from 2000-2003 (EIA 2006).

Data Explanation: Incremental cost of $0.35 per ft^2 and measure life of 17 years are from NGRID 2007. Percent applicable of 18% for this new buildings measure assume that 30% and 50% new buildings savings are phased in one to two years prior to enactment of codes in the policy scenarios (30% in 2012 and 50% in 2020). The levelized cost is calculated to be 2.9 cents/kWh.

33. Efficient New Building (30% Savings)

Measure Description: Incorporating energy efficiency into building design is best achieved at the time of construction. New buildings can achieve major energy savings in heating and cooling, as well as energy-saving appliances.

Basecase: Basecase of 7.2 kWh per ft^2 is an estimate of HVAC, water heating, and lighting end-use electricity intensity for new VA buildings, derived from data for buildings built from 2000-2003 (EIA 2006).

Data Explanation: In New York, estimates show that commercial buildings can reach 30% beyond code at an investment of $0.54/kWh. To be conservative, we estimate $0.70/kWh by doubling the costs of a 15%-beyond-code building. Measure life of 17 years is from NGRID 2007. Percent applicable of 35% for 30% savings new buildings assume that 30% and 50% new buildings savings are phased in one to two years prior to enactment of codes in the policy scenarios (30% in 2012 and 50% in 2020). The levelized cost is calculated to be 2.9 cents/kWh.

34. Tax-Credit Eligible Building (50% Savings)

Measure Description: A federal tax incentive is available for new buildings that are constructed to save at least 50% of the heating, cooling, ventilation, water heating, and interior lighting cost of a building that meets ASHRAE standard 90.1-2001.

Basecase: Basecase of 7.2 kWh per ft^2 is an estimate of HVAC, water heating, and lighting end-use electricity intensity for new buildings in Ohio, derived from data for buildings built from 2000-2003 (EIA 2006).

Data Explanation: Incremental costs of $1.20 per ft^2 are from ACEEE 2004. Measure life of 17 years is from NGRID 2007. The levelized cost is calculated to be 3.0 cents/kWh

Table 29. Commercial Energy Efficiency Measure Characterizations

Measures	Measure Life (Years)	Annual kWh svgs per unit	2007 Ohio Stock	kWh svgs per s.f.	Increment-al cost per unit	Increment -al cost per s.f.	Cost of Conserved Energy (2006$/kWh saved)	Adjust-ment Factor	% Turn-over	Inter-action Factor	Savings in 2025 (GWh)
Existing Buildings											
HVAC											
HVAC tuneup (smaller buildings)	10	24,828	NA	0.53	$ 3,375	NA	$ 0.018	25%	100%	100%	472
Energy management system install	20	5,513	NA	0.10	$ 3,750	$ 0.25	$ 0.055	80%	85%	100%	240
Cool roof	25	NA	NA	0.28	NA	$ 0.12	$ 0.030	35%	100%	100%	345
Roof insulation	25	NA	NA	0.26	NA	$ 0.07	$ 0.020	75%	68%	100%	480
Low-e windows	10	21,977	NA	0.18	$ 6,650	NA	$ 0.039	40%	100%	86%	216
Load-Reducing Measures Subtotal											**1,753**
High-effic. unitary AC & HP	15	1,070	NA	0.19	$ 629	NA	$ 0.057	33%	100%	84%	191
High-effic. unitary AC & HP (65-135 kBtu)	15	3,371	NA	0.29	$ 1,415	NA	$ 0.040	15%	100%	84%	130
High-effic. unitary AC & HP (135-240 kBtu)	15	226	NA	0.21	$ 88	NA	$ 0.038	5%	100%	84%	31
Packaged Terminal HP and AC	13	87	NA	0.19	$ 35	NA	$ 0.043	4%	100%	84%	22
Efficient room air conditioner	23	30,347	NA	0.54	$ 9,900	NA	$ 0.024	33%	74%	84%	393
HVAC Equipment Measures Subtotal											**767**
High-efficiency chiller system	10	3,036	NA	0.30	$ 889	NA	$ 0.038	46%	100%	77%	380
Dual Enthalpy Control	15	8,000	NA	0.14	$ 3,450	NA	$ 0.042	54%	100%	77%	209
Retrocommissioning	3	924	NA	0.37	$ 158	NA	$ 0.063	20%	100%	77%	200
Duct testing and sealing	10	14,308	NA	0.24	$ 6,380	NA	$ 0.058	33%	100%	77%	217
Measures	7	NA	NA	0.30	NA	$ 0.25	$ 0.054	46%	100%	77%	385
HVAC Control Measures Subtotal											**1,391**
HVAC Subtotal											**3,911**
Water Heating											
Energy star commercial clothes washer	11	705	108824	0.00	$ 316	NA	$ 0.037	14%	100%	100%	10
Demand-Controlled Ventilation	12	14,155	NA	0.24	$ 4,067	NA	$ 0.032	24%	100%	99%	202
											212
Refrigeration											
Heat pump water heater	12	8,220		0.36	$ 957	NA	$ 0.013	9%	100%	100%	116
Walk-in coolers & freezers	9	1,268		0.26	$ 177	NA	$ 0.020	15%	100%	100%	143
Reach-in coolers & freezers	10	542		0.13	$ 100	NA	$ 0.024	9%	100%	100%	44
Ice-makers	10	336,00		0.17	$ 37,000	NA	$ 0.014	33%	100%	100%	202
Supermarket (built-up) refrigeration	10	507		0.15	$ 30	NA	$ 0.008	13%	100%	100%	71
Vending machines (to tier 2 ENERGY STAR level)	10	808		0.24	$ 167	NA	$ 0.027	13%	100%	100%	113

Measures	Measure Life (Years)	Annual kWh svgs per unit	2007 Ohio Stock	kWh svgs per s.f.	Increment-al cost per unit	Increment -al cost per s.f.	Cost of Conserved Energy (2006$/kWh saved)	Adjust-ment Factor	% Turn-over	Inter-action Factor	Savings in 2025 (GWh)
Refrigeration Subtotal											**689**
Lighting											
Energy star commercial clothes washer	13	64	0	1.36	$ 4	NA	$ 0.007	56%	100%	100%	2,698
Fluorescent lighting improvements	2	447	0	1.29	$ 60	NA	$ 0.063	12%	100%	100%	552
HID lighting improvements	13	180	0	3.44	$ (22)	NA	$ (0.013)	22%	100%	100%	2,738
Replace incandescent lamps	10	361	0	0.93	$ 48	NA	$ 0.017	38%	100%	71%	904
Occupancy sensor for lighting	20	143	0	1.74	$ 68	NA	$ 0.038	25%	85%	67%	876
Measures	7	NA	NA	0.50	NA	$ 0.25	$ 0.054	46%	100%	63%	519
Outdoor lighting -- improved efficiency	14	174	0	NA	$ 43	NA	$ 0.025	30%	100%	100%	-
											8,286
Office Equipment											
Outdoor lighting -- controls	5	1,410	0	0.97	$ 0	$ 20.00	$ 0.003	50%	100%	100%	1,723
Turn off office equipment after-hours	5	9,557	0	0.56	$ -	$ -	$ -	100%	100%	82%	1,633
											3,356
Appliances/Other											
Vending miser	15	1,815	41763.	NA	$ 453	NA	$ 0.024	25%	100%	100%	19
Hot Food Holding Cabinets	11	339	108824	NA	$ 316	NA	$ 0.037	31%	100%	100%	11
											30
Total Existing											**16,484**
New Buildings											
Turn off office equipment after-hours	17	NA	0	1.09	NA	$ 0.35	$ 0.029	18%	100%	100%	107
Efficient new building (15% savings)	17	NA	0	2.17	NA	$ 0.70	$ 0.029	35%	100%	100%	428
Efficient new building (30% savings)	17	NA	0	3.60	NA	$ 1.20	$ 0.030	6%	100%	100%	121
											656
											17,140

C.3. Industrial Sector

Overview of Approach

The analysis of electricity savings potential was accomplished in several steps. First, the industrial market in Ohio was characterized at a disaggregated level and electricity consumption for key end-uses was estimated. Then cost effective energy-saving measures were selected based on the projected average retail industrial electricity price. The economic potential savings for these measures was estimated by applying the efficiency measures to electricity end-use consumption. The following sections described the process for estimating the savings potential in Ohio.

Market Characterization and Estimation of Base Year Electricity Consumption

The industrial sector is made up of a diverse group of economic entities spanning agriculture, mining, construction and manufacturing. Significant diversity exists within most of these industry sub-sectors, with the greatest diversity within manufacturing. The various product categories within manufacturing are classified using the North American Industrial Classification System (NAICS) (Census 2002).[60]

Comprehensive, highly-disaggregated electricity data for the industrial sector is not available at the state level. To estimate the electricity consumption, this study drew upon a number of resources, all using the NAICS system and a consistent sample methodology. Fortunately, a conjunction of the various economic censuses for each state allows us to use a common base-year of 2002.

We then used national industry energy intensities derived from industry group electricity consumption data reported in the *2005 Annual Energy Outlook* (AEO) (EIA 2005) and value of shipments data reported in the *2002 Annual Survey of Manufacturing* (ASM) (Census 2005) to apportion industrial energy consumption. These intensities were then applied to the value of shipments data for the manufacturing energy groups (three-digit NAICS) in Ohio. These energy consumption estimates were then used to estimate the share of the industrial sector electricity consumption for each sub-sector.

Preparation of Baseline Industrial Electricity Forecast

As is the case for state-level energy consumption data, no state-by-state disaggregated electricity consumption forecasts are publicly available. Several alternate data sources were used to calculate estimated energy consumption growth rates for each state and sub-sector. We made the assumption that energy consumption will be a function of gross state value of shipments (VOS). Electricity consumption, however, will not grow at the same rate as value of shipments. This is because in general, energy intensity (energy consumed per value of output) decreases with time.

Because state-level disaggregated economic growth projections are not publicly available, data was used from Moody's Economy.com. The average growth rate for specific industrial-subsectors was estimated based on Economy.com's estimates of gross state product. We used this estimated industrial energy consumption distribution to apportion the EIA estimate (2005) of industrial energy consumption.

The industry sector is comprised of four sub-sectors: Manufacturing, Mining, Agriculture, and Construction. The manufacturing sector is broken down into 21 subsectors, defined by three digit NAICS codes. In order to most closely match available data from the *ASM* and *AEO*, three subsectors were further broken down to four digit NAICS codes: chemical manufacturing, nonmetallic mineral product manufacturing, and primary metal manufacturing. Table 30 below shows the estimated electrical consumption for all these subsectors in Ohio in 2008.

[60] The industry sector is comprised of four sub-sectors: Manufacturing, Mining, Agriculture, and Construction. Each sub-sector is further broken down into individual industry groups reflecting the many different definitions for the term 'industrial.'

Table 30. 2008 Base-Case Electricity Consumption by Industry in Ohio

Industry	NAICS Code	Electricity (GWh)	(%)
Agriculture	**11**	844	1%
Mining	**21**	592	1%
Construction	**23**	1,236	2%
Food mfg	311	1,987	3%
Beverage & tobacco product mfg	312	607	1%
Textile mills	313	70	0%
Textile product mills	314	91	0%
Apparel mfg	315	55	0%
Leather & allied product mfg	316	27	0%
Wood product mfg	321	487	1%
Paper mfg	322	2,506	4%
Printing & related support activities	323	882	1%
Petroleum & coal products mfg	324	1,670	3%
Chemical mfg	325	13,184	22%
Pharmaceutical & medicine mfg	*3254*	*797*	*1%*
All other chemical products	*-3253,3255-*	*12,387*	*21%*
Plastics & rubber products mfg	326	2,988	5%
Nonmetallic mineral product mfg	327	3,936	7%
Glass & glass product mfg	*3272*	*877*	*1%*
Cement & concrete product mfg	*3273*	*2,545*	*4%*
Other minerals	*3271,3274-*	*514*	*1%*
Primary metal mfg	331	13,765	23%
Iron & steel mills & ferroalloy mfg	*3311*	*4,180*	*7%*
Steel product mfg from purchased steel	*3312*	*1,775*	*3%*
Alumina and Aluminum	*3313*	*3,975*	*7%*
Nonferrous Metals, except Aluminum	*3314*	*2,133*	*4%*
Foundries	*3315*	*1,702*	*3%*
Fabricated metal product mfg	332	2,154	4%
Machinery mfg	333	1,736	3%
Computer & electronic product mfg	334	911	2%
Electrical equipment, appliance, & component mfg	335	1,144	2%
Transportation equipment mfg	336	6,723	11%
Furniture & related product mfg	337	685	1%
Miscellaneous mfg	339	967	2%
Total Industrial Sector		59,246	100%

Market Characterization Results

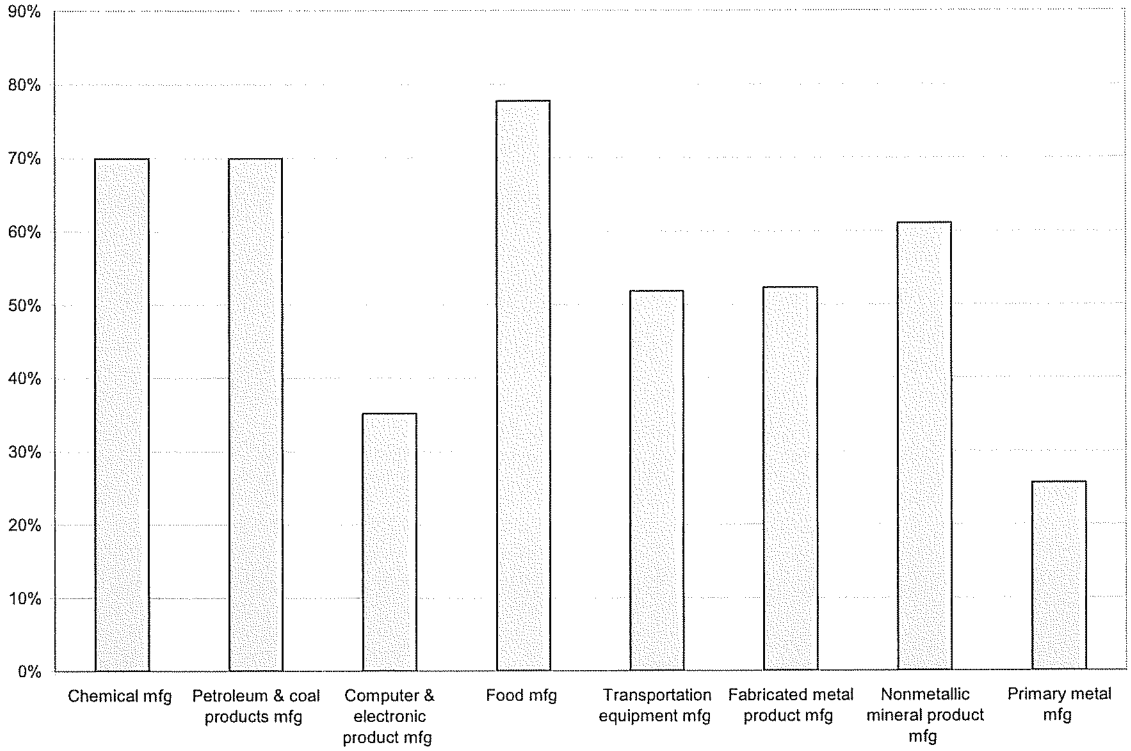
In 2008, the State of Ohio industrial sector consumed 59,246 GWh of electricity. Within the manufacturing sector, the chemical, primary metal, and transportation equipment manufacturing industries are the largest consumers of energy, accounting for over 55% of industrial electricity consumption.

Industrial Electricity End Uses

In order to determine the electricity savings for any technology, the fraction of the electricity to which the technology is applicable must be determined. Much of the energy consumed by industry is directly involved in processes required to produce various products. Electricity accounts for about a third of the primary energy used by industries (EIA 2005). Electricity is used for many purposes, the most important being to run motors, provide lighting, provide heating, and to drive electrochemical processes.

While detailed end-use data is only available for each manufacturing sub-sector and group through the MECS survey (EIA 2005), motor systems are estimated to consume 60% of the industrial electricity (Xenergy 1998). The fraction of total electricity attributed to motors is presented in Figure 23.

Figure 23. Percent of Total Electricity Consumption by Motor Systems

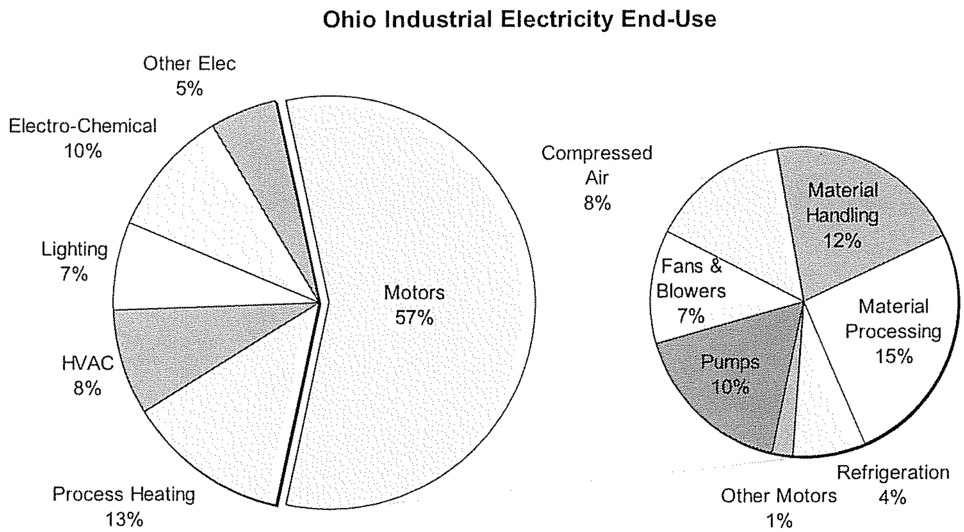


Source: XENERGY (1998)

Motors are used for many diverse applications from fluids (pumps, fans, and air and refrigeration compressors) to materials handling and processing (conveyors, machine tools and other processing equipment). The distribution of these motor uses varies significantly by industry, with material processing being the largest consumer in the sector.

Figure 24 shows the total weighted average of end-use electricity consumption in Ohio with a breakdown of motors use in the state.

Figure 24. Weighted Average of Total Industrial Electricity End-Uses in Ohio with Breakdown of Industrial Motor System End-Uses



While lighting and space conditioning represent a relatively small share of the overall industrial sector electricity consumption, they are important in some of the key industries found in the region such as transportation equipment manufacturing and other mechanical manufacturing and assembling industries, and the electricity savings potential can be significant.

Overview of Efficiency Measures Analyzed

The first step in our technology assessment was to collect limited information on a broad "universe" of potential technologies. Our key sources of information included the U.S. Department of Energy, Office of Industrial Technologies; the Center for the Analysis and Dissemination of Demonstrated Energy Technologies (CADDET); Lawrence Berkeley National Laboratory (LBNL) and American Council for an Energy-Efficient Economy reports; and information from NYSERDA. We did not collect any primary data on technology performance.

Oftentimes, no one source provided all of the information we sought for our assessment (energy use, energy savings compared to average current technology, investment cost, operating cost savings, lifetime, etc.). We therefore made our best effort to combine readily available information along with expert judgment where necessary.

We sought to identify technologies that could have a large potential impact in terms of saving energy. These may be technologies that are specific to one process or one industry sector, or so-called "cross-cutting" technologies that are applicable to a variety of sectors. In estimating energy savings, we first identified the specific energy savings of each technology by comparing the energy used by the efficient technology to the energy required by current processes. Our second step was to "scale up" this savings estimate to see how much energy savings—for industry overall—this technology would achieve. For the most part, we derived specific energy savings information from the various technology assessment studies noted above.

In scaling up the technology-specific energy savings, we relied on our general knowledge of the various industrial processes to which this technology could be applied. We also took into account structural limitations to the penetration of the technology. Additionally, we recognized that market penetration, in the absence of significant policy support, can take time given the slowness of stock turnover in many industrial facilities.

Measures

We identified 14 measures that were cost effective at the average projected industrial electricity rates in Ohio of $0.0744/kWh (see Table 31). The cost and performance of these measures has been developed over the past decade by ACEEE from research into the individual measures and review of past project performance. The costs of many of these measures has increased in recent years as a result of significant increases in key commodity costs such as copper, steel and aluminum, as well as overall manufacturing costs due to energy prices and market pressures. The estimates presented in Table 31) represent ACEEE's most current estimates. We present the full normalized installed measure cost (i.e., the full cost required to install a measure per unit of saved energy) as well as the levelized cost (i.e., the annual cost of the measure amortized over the life of the measure).

Table 31. Cost and Performance of Industrial Measures

		Cost of Saved Energy		
Measure	**Measure Life**	**Installed Cost/kWh**	**Levelized cost/kWh**	**Annual Savings for End-Use**
Sensors & Controls	15	$0.145	$0.014	3%
Energy Information Sys.	15	$0.635	$0.061	1%
Duct/Pipe insulation	20	$0.653	$0.052	20%
Electric supply	15	$0.104	$0.010	3%
Lighting	15	$0.212	$0.020	23%
Advanced efficient motors	25	$0.491	$0.035	6%
Motor management	5	$0.079	$0.018	1%
Lubricants	1	$0.000	$0.000	3%
Motor system optimization	15	$0.097	$0.009	1%
Compressed air manage	1	$0.000	$0.000	17%
Compressed air -advanced	15	$0.001	$0.000	4%
Pumps	15	$0.083	$0.008	20%
Fans	15	$0.249	$0.024	6%
Refrigeration	15	$0.034	$0.003	10%

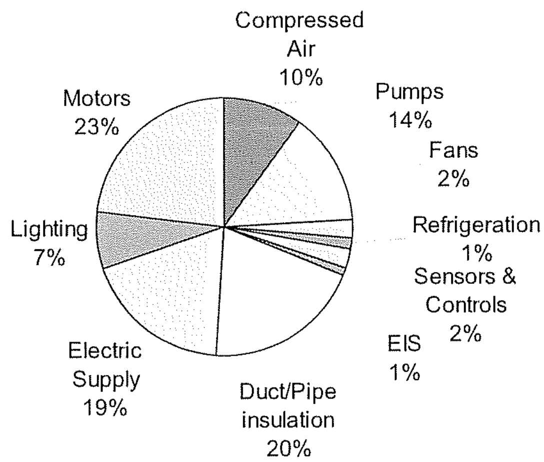
In addition, we estimated the average normalized cost of industrial energy efficiency investments to be $0.275/kWh saved. This estimate was arrived at by estimating the sum of the annual incremental savings for each measure in each industry based on end-use energy distribution and dividing the corresponding total investment required.

Potential for Energy Savings

In Ohio, a diverse set of efficiency measures will provide electricity savings for industry. The application of these measures contributes to total economic electric savings potential of 16%. These savings are distributed as presented in

Figure 25.

Figure 25. Fraction of Savings Electricity Potential by Measure



In addition, this analysis did not consider process-specific efficiency measures that would be applied at the individual site level because available data does not allow this level of analysis. However, based on experience from site assessments by U.S. Department of Energy and others entities, we would anticipate an additional economic savings of 5-10%, primarily at large energy intensive manufacturing facilities. Therefore, the overall economic industrial efficiency resource opportunity for electricity is on the order of 21-26%.

APPENDIX D – DEMAND RESPONSE ANALYSIS

D.1. Introduction

This report defines Demand Response (DR), assesses current DR activities in Ohio, identifies policies in the state that impact DR, uses benchmark information to assess DR potential in Ohio, and identifies barriers in the state that might keep DR contributing appropriately to the resource mix that can be used to meet electricity needs. The analysis concludes with identification of policy recommendations regarding DR.

D.1.1. Objectives of this Assessment

This assessment develops estimates of DR potential for Ohio. Potential load reductions from DR are estimated for the residential, commercial, and industrial sectors (see Section 3). The assessment also includes discussions of reductions possible from other DR programs, such as DR rate designs (see *Section* 3.6).

D.1.2. Role of Demand Response in Ohio's Resource Portfolio

The DR capabilities developed by Ohio utilities will become part of a long-term resource strategy that includes resources such as traditional generation resources, renewable energy, power purchase agreements, options for fuel and capacity, energy efficiency and load management programs. Objectives include meeting future loads at lower cost, diversifying the portfolio to reduce operational and regulatory risk, and allow Ohio customers to better manage their electricity costs. The growth of renewable energy supply (and plans for increased growth) can increase the importance of DR in the portfolio mix. For example, sudden renewable energy supply reductions (e.g., from an abrupt loss in wind) may be mitigated quickly with DR.

D.1.3. Summary of DR Potential Estimates in Ohio

Table 32 shows the resulting load shed reductions possible for Ohio, by sector, for years 2015, 2020, and 2025. Load impacts grow rapidly through 2018 as program implementation takes hold. After 2018, the program impacts increase at the same rate as the forecasted growth in peak demand.

The high scenario DR load potential reduction is within a range of reasonable outcomes in that it has an eleven year rollout period (beginning of 2010 through the end of 2020), providing a relatively long period of time to ramp up and integrate new technologies that support DR. A value nearer to the high scenario than the medium scenario would make a good MW target for a set of DR activities.

The high scenario results show a reduction in peak demand of 3,078 MW is possible by 2015 (8.4% of peak demand); 6,293 MW is possible by 2020 (16.4% of peak demand); and 6,471 MW is possible by 2025 (16.2% of peak demand).

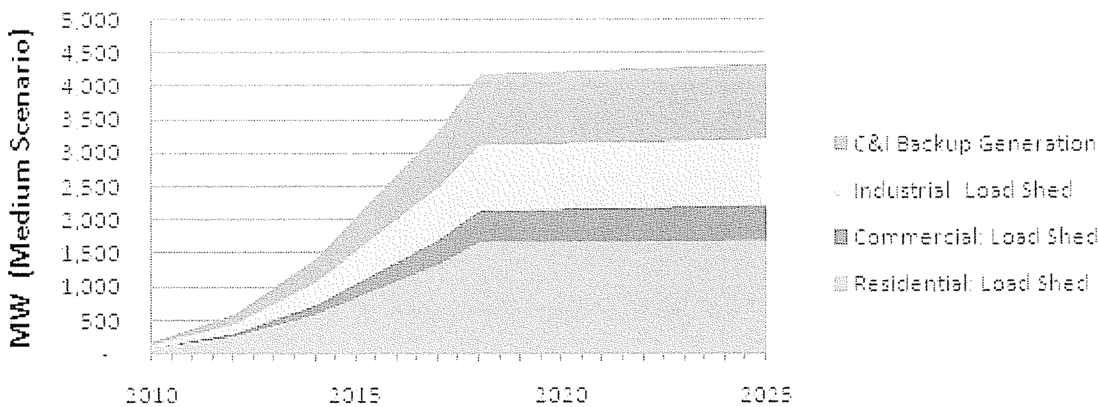
The more conservative medium scenario results show a reduction in peak demand of 2,052 MW is possible by 2015 (5.6% of peak demand); 4,193 MW is possible by 2020 (11.0% of peak demand); and 4,309MW is possible by 2025 (10.8% of peak demand).

Table 32. Summary of Potential DR in Ohio, By Sector, for Years 2015, 2020, and 2025

	Low Scenario			Medium Scenario			High Scenario		
	2015	2020	2025	2015	2020	2025	2015	2020	2025
Load Sheds (MW):									
Residential	502	1,008	1,017	837	1,680	1,696	1,172	2,352	2,374
Commercial	86	184	199	228	491	531	428	921	996
Industrial	206	415	420	464	933	944	824	1,660	1,678
C&I Backup Generation (MW)	393	817	854	524	1,089	1,138	655	1,361	1,423
Total DR Potential (MW)	1,186	2,424	2,490	2,052	4,193	4,309	3,078	6,296	6,471
DR Potential as % of Total Peak Demand	3.2%	6.4%	6.3%	5.6%	11.0%	10.8%	8.4%	16.4%	16.2%
a. See Section 3 for underlying data and assumptions.									

Figure 26 shows the resulting load shed reductions possible for Ohio, by sector, from year 2010, when load reductions are expected to begin, through year 2025.

Figure 26. Potential DR Load Reductions in Ohio by Sector (MW)



D.2. Defining Demand Response

DR focuses on shifting energy from peak periods to off-peak periods and clipping peak demands on days with the highest demands. Within the set of demand-side options, DR focuses on clipping peak demands that may allow for the deferral of new capacity additions, and it can enhance operating reserves available to mitigate system emergencies. Energy efficiency focuses on reducing overall energy consumption with attendant permanent reductions in peak demand growth. Taken together, these two demand-side options can provide opportunities to more efficiently manage growth, provide customers with increased options to manage energy costs, and develop least cost resource plans.

DR is an increasingly important tool for resource planning as power plant siting has grown more difficult and the costs of peak power have increased. Through development of DR capability, utilities can complement existing energy efficiency programs with a set of offerings that provide, at a minimum, 1) enhanced reliability, 2) cost savings, 3) reduced operating risk through resource diversification, and 4) increased opportunities for customers to manage their electric bills.

DR resources are usually grouped into two types: 1) load-curtailment activities where utilities can "call" for load reductions; and 2) price-based incentives which use time-differentiated and/or dispatchable rates to shift load away from peak demand periods and reduce overall peak-period consumption. Interest in both types of DR activities has increased across the country as fuel input prices have increased, environmental compliance costs have become more uncertain, and investment in overall electric infrastructure is needed to support new generation resources.

The mechanisms that utilities may use to achieve load reductions can range from voluntary curtailments to mandatory interruptions. These mechanisms include, but are not limited to:

- Direct load control by the utility using radio frequency or other communications platforms to trigger load devices connected to air conditioners, electric water heaters, and pool pumps;
- Manual load curtailments at commercial and industrial (C&I) facilities, including shutting off production lines and dimming overhead lighting;
- Automated DR ("Auto-DR") technologies utilizing controls or energy management systems to reduce major C&I loads in a pre-determined manner (e.g., raising temperature set points and reducing lighting loads); and
- Behavior modifications such as raising thermostat set points, deferring electric clothes drying in homes, and reducing lighting loads in commercial facilities.

D.3. Rationale for Demand Response

DR alternatives can be implemented to help ensure that a utility continues to provide reliable electric service at the least cost to its customers. Specific drivers often cited for DR include the following:

- **Ensure reliability** – DR provides load reductions on the customer side of the meter that can help alleviate system emergencies and help create a robust resource portfolio of both demand-side and supply-side resources that meet reliability objectives.
- **Reduce supply costs** – DR may be a less expensive option per megawatt than other resource alternatives. DR resources compete directly with supply-side resources in many regions of the country. Portfolios that help lower the increase in customers' expenditures on electricity over time represent an increasingly important attribute from the perspective of many energy customers.
- **Manage operational and economic risk through portfolio diversification** – DR capability is a resource that can diversify peaking capabilities. This creates an alternative means of meeting peak demand and reduces the risk that utilities will suffer financially due to transmission constraints, fuel supply disruptions, or increases in fuel costs.
- **Provide customers with greater control over electric bills –** DR programs would allow customers to save on their electric bills by shifting their consumption away from higher cost hours and/or responding to DR events. The ability to manage increases in energy costs has increased in importance for both residential and commercial customers. Standard residential and commercial tariffs provide customers with relatively few opportunities to manage their bills.
- **Address legislative/regulatory interest in DR –** Ohio's adopted renewable portfolio standards (RPS) include demand side options among the means by which the standards can be met. Senate Bill 221 includes strong standards for renewable energy and energy efficiency that will result in 12.5% of Ohio's electricity coming from renewable sources of power and a 22% cumulative reduction in energy usage by 2025. Also, EPACT 1252 has been adopted in Ohio, requiring electric distribution companies to offer dynamic pricing to all customer classes and to make available smart meters to all customers.

DR is gaining greater acceptance among both utilities and regulators in the United States. A 2006 FERC survey found that 234 "entities" were offering direct load control programs and the FERC's assessment noted that "there has been a recent upsurge in interest and activity in DR nationally and, in particular, regional markets" (FERC 2006).[61] The recent proliferation of DR offerings has been promoted in part by utilities hoping to reduce system peaks while offering customers more control over electric bills and in part by regulators. Although federal legislation has not been the driver behind the trend, it is one of many indications, at all levels of government and industry, of the growing support for DR.[62]

Many states experience significant reductions in peak demand from Demand-Side Management (DSM) programs (which include DR programs). Regulatory filings show that California experienced 495 MW in peak demand reductions in 2005 (1% of total peak demand); New York experienced 288 MW reductions in 2005 (1% of total peak demand); and Texas experienced 181 MW in reductions in 2005 (1% of total peak demand) from DSM programs. These results are annual values that do not consider the cumulative (i.e., year-to-year) impacts that accrue over the lifetimes of the conservation measures. Therefore, cumulative percentage reductions in peak demand are much higher than the annual figures stated.

D.4. Assessment Methods

As has been shown in numerous other jurisdictions across North America, well-designed DSM programs incorporating DR strategies represent an effective and affordable option for reducing peak demand and meeting growing demand for electricity. This effort estimated conservative peak demand reduction for Ohio using local energy use characteristics, demographics, and forecast peak demand, assuming relatively basic DR strategies comprising responsive reductions in demand. The following research approach was used to conduct the analysis:

- Review of existing information regarding Ohio's customer base including:
    - Customer counts and average annual energy consumption by market segment;
    - Forecasts of future energy consumption and customer counts by market segment;
    - Previous DSM planning and potential studies.
- Review of additional publicly-available secondary sources including:
    - U.S. DOE's Commercial Building Energy Consumption Survey (CBECS) and Residential Energy Consumption Survey (RECS) data;
    - Previous studies relevant to the current effort completed by Summit Blue in other regions as well as entities in other jurisdictions.
- Development of baseline profiles for residential and commercial customers. These profiles include current and forecast numbers of customers by market segment and electricity use profiles by segment.
- Incorporation of ACEEE baseline data and reference case into analysis.
- Obtaining state-level data when possible and estimation of information for the State of Ohio, when state-level data was not available.

[61] The FERC report uses the term "entities" to refer to all types of electric utilities, as well as organizations such as power marketers and curtailment service providers.

[62] The federal Energy Policy Act of 2005 (EPAct) directs the Secretary of Energy to "identify and address barriers to the adoption of demand response programs," and the Act declares a U.S. policy in support of "State energy policies to provide reliable and affordable demand response services." EPAct directed FERC to conduct its survey of DR programs and also directed the U.S. Department of Energy to report on the benefits of DR and how to achieve them (DOE, 2006). Separately, a *National Action Plan for Energy Efficiency,* which advocates DR and other efficiency efforts, was developed by more than 50 U.S. companies, government bodies, and other organizations, including co-chairs Diane Munns, President of NARUC and Jim Rogers, President and CEO of Duke Energy (U.S. Environmental Protection Agency, 2006). Other utility industry members of the Leadership Group included Southern Company, AEP, PG&E, TVA, PJM Interconnection, ISO New England, and the California Energy Commission.

- Development of a spreadsheet approach for estimating peak demand reduction potential associated with the DR programs/technologies deemed to be most applicable to Ohio. Estimates are developed for three scenarios—low, medium and high case scenarios.
- Conference calls with ACEEE staff and industry professionals to discuss assessment processes and legislative, regulatory, and other factors specific to the State of Ohio.
- Incorporation of all sources of information and references into report, noting on each figure the source of the information.
- Revision of draft report based on comments from ACEEE, industry specialists and utility commenters.

The DR potential estimated used historical data and experience to obtain curtailment levels. This potential is assumed to be the achievable potential that would be cost effective, given the range of incentives that are typically required and the range of the utilities' avoided costs. A cost-effectiveness analysis was not performed for this study. Sufficient incentives could be provided to customers to encourage load reductions while maintaining a cost-effective program given avoided costs of approximately $76 per kW (based on the analysis reference case).

D.4.1. State of Ohio - Background

A sound strategy for development of DR resources requires an understanding of Ohio's demand and resource supply situation, including projected system demand, peak-day load shapes, and existing and planned generation resources and costs.

Ohio utilities serves a population of over 11.5 million, generation over 155 million megawatt hours of electricity, that is expected to have a system peak load of almost 30,000 MW in 2009 (ACEEE base case for Ohio).

Electricity demand in Ohio has fluctuated over the past 15 years (EIA 2009). Total consumption has grown only slightly. Total retail sales in 2007 in Ohio totaled 161.5 billion kWh. This is an aggregate figure for all sectors, including industrial, commercial and residential.

Ohio has been and likely will continue to be a modest importer of energy and likewise be dependent on out-of-state capacity. In 2007, in-state generation provided 89% of total Ohio retail sales, thus requiring import of approximately 11% (EIA 2009).

Most of Ohio is located within the PJM regional transmission organization (RTO), the largest power region in the US with installed capacity of over 164,000 MW. PJM covers 11 states including Pennsylvania, New Jersey, Maryland, Delaware, Virginia, and parts of Ohio, Indiana, Illinois, Michigan and North Carolina. See Section 2.2 for a discussion of PJM's DR programs.

The five largest electricity retailers in Ohio are the following entities, with percent contribution in parentheses:

- Ohio Power Co (17%)
- Ohio Edison Co (13%)
- Duke Energy Ohio Inc (13%)
- Columbus Southern Power Co (13%)
- Cleveland Electric Illum Co (11%) (EIA 2009).

D.4.2. Assessment of Utility DR Activities

The PJM Interconnection provides opportunities for DR to realize value for demand reductions in the Energy, Capacity, Synchronized Reserve, and Regulation markets. The FERC authorized PJM to provide these opportunities as permanent features of these markets in early 2006 (PJM 2008a).

The PJM Economic Load Response Program enables customers to voluntarily respond to PJM Locational Marginal Price ("LMP") prices by reducing consumption and receiving a payment for the reduction. The growth of participation by end-use customers since 2002 is significant, with over 225,000 MWh of participation in 2006 (PJM 2008a).

Under the Reliability Pricing Model (RPM), customers can offer DR as a forward capacity resource. DR providers can submit offers to provide a demand reduction as a capacity resource in the forward RPM auctions. In the first annual RPM auction which was held in April 2007 for the 2007/2008 planning period, 127.6 MW of demand response offers were cleared (PJM 2008a).[63]

PJM held a symposium on DR in May, 2007 that was attended by a broad mix of stakeholders and subject matter experts. One of the most prominent themes to emerge from the symposium was the need for coordination between retail and wholesale markets in order to increase DR participation in PJM's markets. The participants at the PJM Symposium on DR identified priority opportunities, which formed the basis of a "Demand Response Roadmap" to guide action (PJM 2008b).

Duke Energy offers the following programs:

- Smart $aver Incentive Program for rebates on products ranging from clothes washers to window films to chillers. Incentives are prescriptive, based on the efficiency and capacity of equipment.
- PowerShare pricing program, in which participants are remunerated for reducing load below a customer-specific baseline during summer weekdays when market prices are high. There are two options: a voluntary and mandatory one. Payments are higher for the mandatory program, but there is a penalty for not meeting the committed load shed during notified events.
- Real Time Pricing Program, in which participants are alternatively credited or charged, based on the hourly price, for usage below or above a pre-determined customer baseline load profile.

Ohio Edison (a subsidiary of First Energy) offers an interruptible option and a voluntary real-time pricing rate:

- OE's Interruptible Rider is for customers on the General Service Large rate (with an interruptible load of at least 1000 kW), who can curtail within 10 minutes of notification. A demand credit is given each month per kVA of interruptible load based on the customer's load that is coincident with the utility's peak demands.
- A "block-and-swing" Experimental Market Based Tariff is available where customers designate a market exposure percentage representing the amount of usage to be applied to real-time pricing. The market exposure percentage must be at least 5% but not more than 30%.

Toledo Edison and the Illuminating Company (Cleveland Electric), both subsidiaries of First Energy, also offer an Experimental Market Based Tariff to customers whose peak load is greater than 100 kW. The customer designates a market exposure percentage representing the amount of usage to be applied to real-time pricing. The remaining usage is priced under a fixed price tariff.

D.4.3. Assessment of Current State Policies Affecting DR

Many states have put in place renewable portfolio standards (RPS) to ensure that a minimum amount of renewable energy is included in the portfolio of the electricity resources serving a state. Many RPS include demand side options among the means by which the standards can be met. In April 2008, a unanimous vote in the Ohio State Senate passed Sub Senate Bill 221 that was previously passed by

[63] It is not known at this time what portion of PJM DR reductions have been fulfilled by Ohio customers.

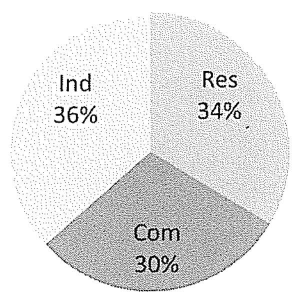
the Ohio House. Included in the legislation are strong standards for renewable energy and energy efficiency that will result in 12.5% of Ohio's electricity coming from renewable sources of power and a 22% cumulative reduction in energy usage by 2025.

Section 1252 of the Energy Policy Act of 2005 (EPACT) includes demand side management provisions (in the form of a new PURPA Standard on Demand Response and Advanced Metering) and directed States and other bodies with authority over utilities to determine whether utilities under their jurisdiction to implement such. Ohio opened a proceeding in December 2005. Via a March 2007 Finding and Order, the Ohio Commission adopted EPACT 1252 and directed electric distribution companies to offer dynamic pricing to all customer classes and to make available smart meters to all customers. This proceeding is still open, however, and further activity is planned. In May 2007, the Commission opened a new proceeding to facilitate a series of technical workshops on EPACT 1252. So far, there have been two workshops: one in July 2007 and one in September 2007.

D.4.4. Energy and Peak Demands

Use of energy in Ohio is distributed to end use categories as follows: 34% residential, 30% commercial, and 36% industrial sectors (see Figure 27). Energy consumption in Ohio's industrial sector ranks among the highest in the Nation (EIA 2009).

Figure 27. Energy Sales in Ohio by Sector (2007)

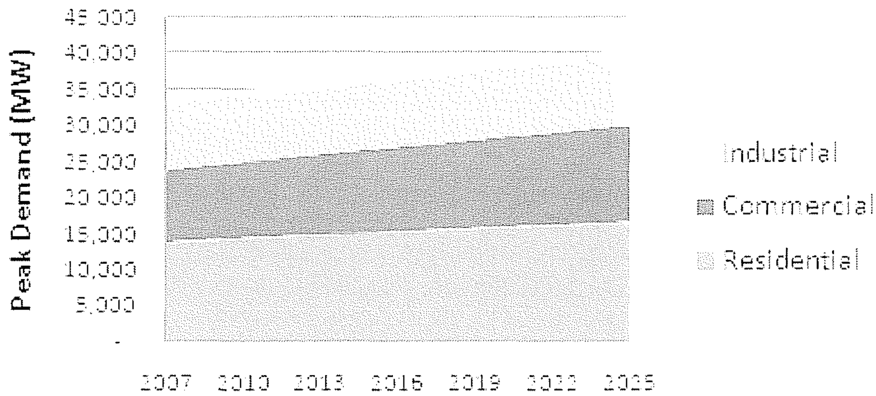


Source: EIA (2008a)

In 2007, the total summer peak load was 33,259 MW and is projected to grow an average of 1% per year through 2025.

Figure 28 displays peak demand by sector. In 2007, residential peak demand was 13,443 MW (41%); commercial was 9,900 MW (30%); and industrial was 9,717 MW (29%).

Figure 28. Peak Demand by Sector in Ohio (MW)



Source: ACEEE Reference Case for Ohio

Smart Grids and Advanced Metering Infrastructure (AMI)

The 2005 EPAct provisions for DR and Smart Metering has lead to a number of states and utilities piloting and implementing a Smart Grid, or sometimes referred to as Advanced Metering Infrastructure (AMI).

Smart Grid is a transformed electricity transmission and distribution network or "grid" that uses robust two-way communications, advanced sensors, and distributed computers to improve the efficiency, reliability and safety of power delivery and use. For energy delivery, the Smart Grid has the ability to sense when a part of its system is overloaded and reroute power to reduce that overload and prevent a potential outage situation. The end user is equipped with real-time communication between the consumer and utility allowing optimization of a consumer's energy usage based on environmental and/or price preferences (for example, critical peak pricing and time of use rates).

AMI provides:

- Two-way communication between the utility and the customer through the customer's smart meter.
- More efficient management of customer outages (location, re-routing).
- More accurate meter reading (minute, 15 minute intervals).
- More timely collection efforts (real time).
- Improved efficiency in handling service orders.
- More detailed, timely information about energy use to help customers make informed energy decisions (real time).
- Ability to reduce peak demand.
- More innovative rate options and tools for customers to manage their bills.

Smart Energy Pricing provides:

- Incentives to customers to shift energy away from critical peak periods
- The ability to for customers to save on their electricity bills.
- Lower wholesale prices for capacity and transmission—in the longer term.
- Improved electric system reliability, as demand is moderated.
- Potential to defer new transmission and generation.

The Smart Grid is comprised of multiple communication systems and equipment, which interoperability is crucial. Not all communication protocols are applicable to every utility's geography; therefore, pilots are essential in testing the equipment and communication software for various geographies. Furthermore, the identification of those geographic regions with the best return on investment during a pilot will aid the staged implementation plan. Standards are continuing to be researched through organizations including: 1) IntelliGrid—Created by the Electric Power Research Institute (EPRI); 2) Modern Grid Initiative (MGI) is a collaborative effort between the U.S. Department of Energy (DOE), the National Energy Technology Laboratory (NETL), utilities, consumers, researchers, and other grid stakeholders; 3) Grid 2030—Grid 2030 is a joint vision statement for the U.S. electrical system developed by the electric utility industry, equipment manufacturers, information technology providers, federal and state government agencies, interest groups, universities, and national laboratories; 4) GridWise—a DOE Office of Electricity Delivery and Energy Reliability (OE) program; 5) GridWise Architecture Council (GWAC) was formed by the U.S. Department of Energy; and 6) GridWorks—A DOE OE program.

Principal benefits of Smart Grid technologies for DR include increased participation rates and lower costs. In 2009, Dominion plans to deploy 200,000 smart meters as part of a large demonstration program of smart grid technology in urban and rural areas of Dominion's service territory. Dominion expects to improve customer service and business operations through advanced system control, real-time outage notification, and power quality monitoring. As part of this program, Dominion is deploying a number of smart thermostats for a residential critical peak pricing pilot during the summer of 2008. Dominion will measure customer responsiveness to changing energy prices and the impact on energy demand during peak usage periods (Utility Products 2008).

These developments in technology allowing real time signaling and automated response will improve DR capabilities. However, existing technology exists for successful DR implementation and it is important to point out that there are no technology obstacles to effective DR.

D.5. Assessment of DR Potential in Ohio

This section examines and quantifies DR potential in Ohio. Section 5.1 outlines the general DR program categories, while Sections 5.2 and 5.3 outline the DR potential in the residential and commercial /industrial sectors, respectively. Section 5.4 discusses the load reduction potential from backup generation and Section 5.5 explains the issues surrounding rate pricing, even though benefits from this form of DR are not quantified in this analysis. Section 5.6 concludes with a summary of DR potential in Ohio.

D.5.1. Demand Response Program Categories

For the purposes of assessing DR alternatives, the following programs could be employed in Ohio to achieve the DR potential we outlined in this report:

Resource Category	Characteristics
Direct Load Control (DLC)	Direct load control (DLC) programs have typically been mass-market programs directed at residential and small commercial (<100 kW peak demand) air conditioning and other appliances. However, an emerging trend is to target commercial buildings with what has become known as Automated Demand Response or Auto-DR. Increased use and functionality of energy management systems at commercial sites and an increased interest by commercial customers in participating in these programs is driving growth in automated commercial curtailment in response to a utility signal. The common factor in these programs is that they are actuated directly by the utility and require the installation of control and communications infrastructure to facilitate the control process.
Callable Customer Load Response	With this type of program, utilities offer customers incentives to reduce their electric demand for specified periods of time when notified by the utility. These programs include curtailable and interruptible rate programs and demand bidding/buyback programs. Curtailable and interruptible rate programs can be used as "emergency demand response" if the advanced notice requirements are short enough. All customer load response programs require communications protocols to notify customers and appropriate metering to assess customer response.
Scheduled Load Control	This is a class of programs where customers schedule load reductions at pre-determined times and in pre-determined amounts. A variant on this theme is thermal energy storage which employs fixed asset technology to reduce air conditioning loads consistently during peak afternoon load periods.
Time-differentiated Rates	Pricing programs can employ rates that vary over time to encourage customers to reduce their demand for electricity in response to economic signals—in some cases these load reductions can be automated when a price trigger is exceeded. An example is a critical peak price which is "called" by the utility or system operator. In response to this critical price, residential customers can have AC cycling or temperature setbacks automatically deployed. Similar automated responses can be deployed by commercial customers. These rate programs are not analyzed for this assessment, but are further discussed in Section 3.5.

D.5.2. DR for Residential Customers

Air conditioner and other appliance direct load control (DLC) is the most common form of non-price-based DR program in terms of the number of utilities using it and the number of customers enrolled. According to FERC's 2006 assessment of DR and advanced metering, there are 234 utilities (including municipalities, cooperatives, and related entities) with DLC programs across the United States. Approximately 4.8 million customers are participating in DLC programs across the country (FERC 2006).

The prominent and growing role of air conditioning in creating system peaks makes it a high-profile candidate for DR efforts. The advances in DR technology that make AC load management economically viable make AC load control a high-priority program—one that has been proven reliable and effective at many utilities. Pool pumps are also a relatively easy and non-disruptive load that can be controlled for DR purposes.

Residential Control Strategies

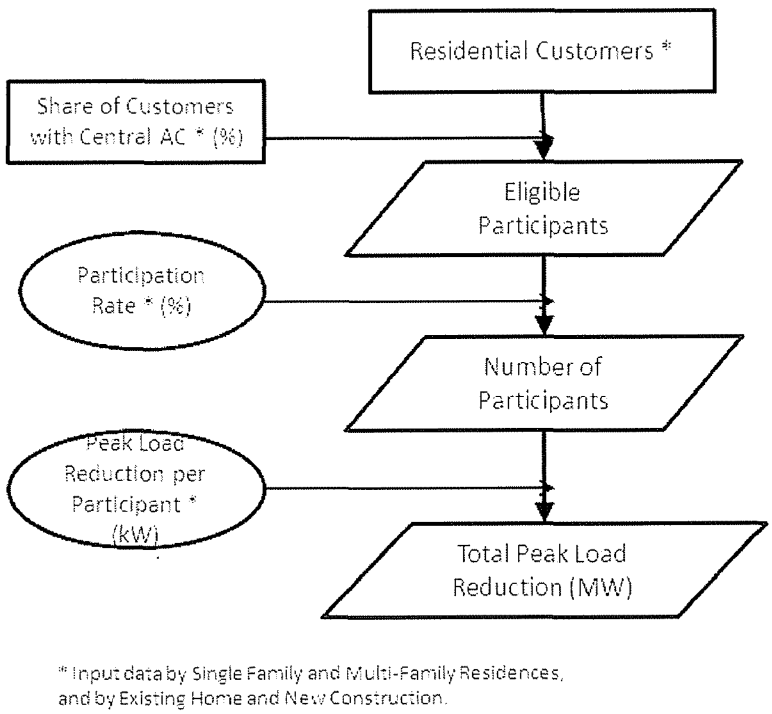
There are two basic types of control strategies: AC cycling and temperature offset. AC cycling limits ACs being on to a certain number of minutes than they otherwise would have been on. Some techniques limit ACs to being on for 50% of the minutes they would otherwise have been on. A temperature offset increases the thermostat setting for a certain period of time, for a certain number of degrees higher than it would have otherwise been set. This essentially causes the AC compressor to cycle as the temperature set-back reduces the AC demand. Sequential thermostat setbacks, i.e., one degree in a hour one, two degrees in hour two, three degrees in hour three, and four degrees in hour four can mimic an AC cycling strategy.

Cycling strategies have evolved where an optimal impact on peak kW demand may be obtained by varying the cycling time across the hours of an event. For example, there may be one hour of pre-cooling followed by 33% cycling in the first hour, 50% cycling in the second hour, 66% cycling in the third hour and dropping back to 33% in the fourth hour. Strategies like this have been deployed in pilot programs at Progress Energy Carolinas (PEC) and in PSE&G's MyPower pilot program. This type of strategy requires that forecasters accurately predict the hour(s) in which the peak system demand will occur.

Assessment of DR Potential in Residential Homes in Ohio

For Ohio, estimates for possible load reductions for residential housing units were obtained by applying the methodology displayed in Figure 29.

Figure 29. Residential Peak Load Reduction



The figure shows how load reductions and participations rates are applied to housing data. Items listed in rectangular shapes are factual inputs; items in circular shapes are assumptions; and items in parallelogram shapes are results.

D.5.3. Load Reductions

Recent surveys show that DLC programs are being implemented by a number of utilities. Load impacts are dependent on many variables. The control strategy used, the outdoor temperature, the time of day, the customer segment, ease of and ability to override control, reliability of communication signals, age and working condition of installed equipment, and local AC use patterns all have significant effects on the load impact. Even within a single program, there is variability in impacts across event days that cannot yet be fully explained. Measuring impacts typically requires expensive monitoring equipment and as a result is often done on small sample sizes.

Even with this variability, a review of reported impacts does show some general consistencies. As expected, impacts increase as the duty cycle goes up. Table 33 shows the average reported kW impact based on 20 load control impact studies for programs based on the duty cycle used. These results support the oft-quoted rule-of-thumb that the load impact for 50% duty cycling is 1 kW per customer, which is the impact used in this analysis. However, many homes will experience an impact greater than I kW, especially newer homes.

Table 33. Average Load Impacts by Cycling Strategy for AC DLC Programs

Cycling Strategy	Average Load Impact KW/Customer
33%	0.74
45%	0.81
50%	1.04
66%	1.36

Source: Summit Blue 2007b.

Customer type also makes a difference. In a few cases where single-family and multi-family impacts were measured separately, multi-family impacts were 60% of single-family, and thus a 0.6kW load reduction is applied in this analysis for multi-family units (Summit Blue 2007b).

Eligible Residential Customers

All residential customers with central air-conditioning that live in areas that can receive control signals are considered eligible for the direct load control program. This includes single family and multi-family housing units. Residential accounts without central AC are assumed to have no participation. The ACEEE Reference Case reports that 64% of all housing units have CAC in Ohio – both single family and multi-family.

Multi-family housing units often have building tenants which are not the account holders, therefore accounts are often aggregated into buildings. Some accounts have a master meter for the entire building, including tenants. Some accounts are for the "common" building loads (i.e., those loads that are part of a building account such as elevators, A/C (if applicable), lobby lighting, etc.), but individual tenants in these buildings have their own accounts. There, multi-family units often have fewer units with central AC than single family. However, in this analysis, due to data constraints, 64% was applied to both single and multi-family customers, and leads to a more conservative estimate of impacts.

Residential Participation Rates

Participation rates experienced in AC DLC programs vary across utilities typically from 7% of eligible customers to 40%, depending upon the effort made in maintaining and marketing the program (Summit Blue 2007a). The utilities with the low levels of participation had essentially stopped marketing the program in recent years. Utilities with programs with sustained attention to customer retention or recruitment show higher participation rates than utilities with one-time or intermittent promotion. In Maryland, BG&E's Demand Response Service program anticipates a residential participation rate of 50%, or approximately 450,000 controlled units (BGE 2007). The pilot phase of this program was conducted from June 1 through September 30, 2007, and 58% received a "smart" load control switch, and 42% had a "smart" thermostat installed (BGE 2007). One study examined 15 AC DLC programs nationwide and found an average of 24% participation for eligible customers (Summit Blue 2008a).[64] For this analysis, 3 typical yet conservative scenarios were used: a low scenario of 15% for eligible customers; a medium scenario of 25%; and a high scenario of 35%.

Results

Table 34 displays the input data and results. In summary, the results for residential programs reveal that a medium scenario reduction of 837MW is possible by 2015 (with 502MW possible by the low scenario, and 1,172MW by the high scenario). By 2020, 1,680MW is achievable through the medium scenario (with 1,008MW possible by the low scenario, and 2,352MW by the high).

Table 34. Potential Load Reduction from AC-DLC In Ohio Residential Homes, in years 2015 and 2020

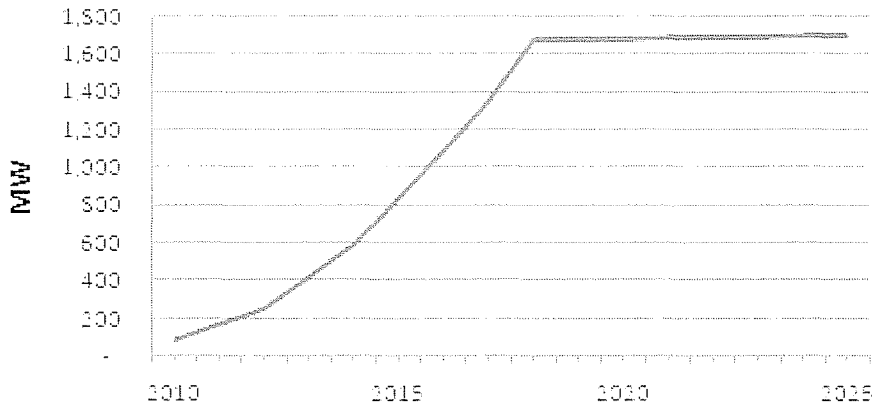
INPUTS	**2015**	**2020**
Residential Peak Demand (MW)	14,826	15,618
Residential Customers (in thousands)[a]: Total	11,472	11,513
Single Family	8,777	8,793
Multi-Family	2,695	2,720
Eligible Residential Customers: Single and Multi-Family[b]	64%	
Load Reduction per AC-DLC per Single-Family Unit (kW)	1.0	
Load Reduction per AC-DLC per Multi-Family Unit (kW)	0.6	
DR Participation Rates of eligible customers:		
Low Scenario	25%	
Medium Scenario	25%	
High Scenario[c]	35%	
RESULTS	**2015**	**2020**
Residential Potential DR Load Reduction (MW):		
Low Scenario	502	1,008
Medium Scenario	837	1,680
High Scenario	1,172	2,352

Notes:
a. Residential customers reflect number of housing units, as reported from Economy.com.
b. Analysis assumes residences with central AC are eligible. Residential accounts without central AC are assumed to have no participation. Central AC percents obtained from ACEEE Reference Case.
c. Higher participation than applied in the High Scenario is possible through design of program features, such as "opt-out" participation where participants are included in a program unless they chose to "opt-out."

Figure 30 shows the resulting residential load shed reductions possible for Ohio, from year 2010, when load reductions are expected to begin, through year 2025.

Figure 30. Potential Residential Load Shed in Ohio (Medium Scenario)

[64] Programs where participants are included in a program unless they chose to "opt-out" experience much higher participation rates. One utility is proposing a "hybrid" program for new construction, where existing customers must opt-in and new construction customers must opt-out. This program assumes that 70% of new construction customers will enroll in the initial years, and 80% in later years (Summit Blue, 2008b).



D.5.4. Room Air Conditioners

Other DR residential programs could involve tapping into the potential for callable load reductions from room air conditioners. At least one prominent DR provider is exploring the possibility of having manufacturers of room AC units embedding a home-area-network communication device into new units. This would enable cycling of room air conditioners without the need to install radio frequency load switches commonly used for residential direct load control applications. Callable load reductions from room air conditioners would provide a significant boost to load control capability and these reductions would be dispatchable in less than ten minutes. Some utilities are projecting to add a large number of new room air conditioners in the next five to ten years. The additional participation of a fraction of these room AC units could provide a substantial increase to the AC DLC program.

D.5.5 Other Appliances

Based on the experiences of other utilities, expanding the equipment controlled to other equipment beyond AC units can produce additional kW reductions. This could include electric hot water heaters and pool pumps. However, the saturation of electric hot water heaters is lower than for air conditioning, and control of hot water heaters generally produces only about one-third the load impact of air conditioners, especially in the summer when Ohio utilities would most likely be calling DR events.

D.6. Commercial and Industrial DR Potential in Ohio

Appropriate commercial sector DR programs will vary according to customer size and the type of facility. Direct load control of space conditioner equipment is a primary DR strategy intended for small commercial customers (e.g., under 100 kW peak load), although TOU rates combined with promising new thermal energy storage technologies could prove an effective combination. Mid-to-large commercial customers and smaller industrial customers could best be targeted for a curtailable load program requiring several hours of advanced notification or, where practical, for an Auto-DR program that can deliver load reductions with no more than ten minutes of advance notice. Thermal energy storage and other scheduled load control programs may also be applicable for some larger buildings or water pumping customers. In this assessment of DR potential, the focus is on the use of direct load control and curtailable load response programs. Studies have shown that pricing programs, specifically dispatchable pricing programs such as critical peak pricing (CPP) programs can provide similar impacts. These pricing programs are discussed in Section 5.2. However, for the purposes of this assessment, a focus on these load response programs is believed to be able to fully represent the DR potential, even though pricing programs could be used instead of these curtailable load programs with equal, or in some cases, greater efficiency.

The following DR program descriptions apply to both commercial and industrial customers:

- Small business direct load control (air conditioning)—Small commercial customers (under 100 kW peak load) account for a majority of customer accounts but typically only about one-quarter of total commercial load. Due to the nature of small businesses, particularly their small staffs for which energy management is a relatively low priority, it is not practical to rely on active customer response to load control events. Thus, small businesses may best be viewed in the same way as residential customers for purposes of DR.

- Curtailable load program—This program would be applicable to commercial and industrial customers willing to commit to self-activated load reductions of a minimum of perhaps 50 kW in response to a notice and request from a utility. The minimum curtailment threshold is designed to improve program cost-effectiveness by ensuring that recruitment and technical assistance costs are used for customers who can deliver significant load reductions. Advanced notice requirements would likely be two hours— long enough to allow customers an opportunity to prepare but short enough to maintain the DR resource as a viable resource that can be dispatched by operations staff. Enabling technologies would vary greatly, but utilities would educate customers about alternatives and could work with equipment vendors to facilitate equipment acquisition and installation. Incentives would be paid as capacity payment (in $/kW-month) or a discount on the customers' demand charges. Utilities could also offer a voluntary version of the program to attract greater participation. Customers would not commit to load reductions, but incentives would be lower and would be paid only on the reductions achieved during curtailment events.

- Automated demand response (Auto-DR)—This program would be marketed to facilities such as high-rise office buildings and large retail businesses that have energy management and control systems (EMCS) that monitor and control HVAC systems, lighting, and other building functions. The benefits of Auto-DR over curtailable load programs include customer loads curtailments with as little as ten minutes notice and greater assurance that customers will reduce loads by at least their contracted amount. Incentives would be paid as either capacity payments or demand charge discounts, but would be greater than for curtailable load program participants due to the additional technology investment that may be required and the allowance of curtailments on relatively short notice. Utilities would offer extensive technical assistance in setting up Auto-DR capability and would potentially provide financial assistance as well for customers making long-term commitments.

- Scheduled load control programs (including thermal energy storage)—Scheduled load control can help reduce utility peak demand, especially through shifting of space cooling loads enabled by thermal energy storage technologies. Large-customer TES systems could be promoted along with customer commitments to reduce operation of chillers or rooftop air conditioners during specified peak hours. Customers' return on investment can be increased by encouraging migration to a TOU rate, which would offer a rate discount for many of the hours that TES systems are recharging cooling capacity. Water pumping systems are typically good candidates for scheduled load control programs and utilities can investigate opportunities in the municipal water supply and irrigation sectors. Other, less traditional, opportunities may also be available, such as the leisure/resort industry's limiting recharging of electric golf carts to off-peak hours.

- Emergency under-frequency relay (program add-on)—Under-frequency relays (UFRs) automatically shut off electrical circuits in response to the circuits exceeding pre-set voltage thresholds specified by the utility. Use of UFRs is a valuable addition to a DR portfolio because the load response is both automatic and virtually instantaneous. UFRs can best be integrated into another DR program where participants are already engaging in load curtailment activities. It is expected that some customers who might consider participating in a DR program will not be willing to allow loads to be controlled via UFR since they would not receive any advanced notice. Incentives would also need to be greater to attract participants and provide acceptable compensation. However, the benefits of UFRs warrant their consideration as part of a utility's proposed DR portfolio.

D.6.1. Commercial DR Potential in Ohio

To estimate potential load reductions for commercial units, a straight-forward approach of applying load shed participation rates and curtailment rates directly to commercial peak demand.

First, assumptions were made on the percentage of commercial customers who are willing to participate in DR programs. One study applied commercial participation rates ranging from 11% to 48% for commercial customers (Summit Blue 2008a). Table 35 displays participation rates for various types of commercial customers, disaggregated into two different peak demand categories (<300kW and >300kW).

Table 35. Examples of Commercial Load Shed Participation Rates

	Peak Category	
Customer Segment	<300kW	>300kW
Office Buildings	11% - 15%	45% - 48%
Hospitals	13%	48%
Hotels	14%	45%
Educational Facilities	13%	43%
Retail	11%	42%
Supermarkets	12%	33%
Restaurants	11%	39%
Other Government Facilities	15%	44%
Entertainment	13%	41%
Source: Summit Blue 2008a.		

Because facility-specific data was not available for Ohio, three conservative scenarios for participation rates were applied. A medium-scenario load participation rate of 20% was applied as it appears to be an average participation rate found by utilities with DR programs in place. A low scenario of 10% and a high scenario of 30% are applied.

Then, assumptions were made for curtailment rates, based on existing estimates of the fraction of load that has been shed by commercial customers enrolled in event-based DR programs callable by the utility.

Table 36. Examples of Commercial Curtailment Rates

displays curtailment rates for various types of commercial customers, which range from 13% to 43%. For the purposes of this analysis, 3 conservative scenarios were applied: a low curtailment rate of 15%, a medium curtailment rate of 20%, and a high rate of 25%.

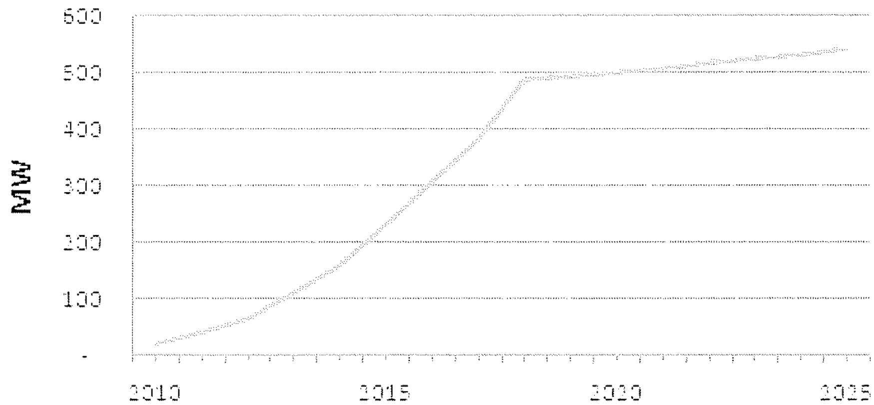
Table 36. Examples of Commercial Curtailment Rates	
Customer Segment	Average Curtailment Rate
Office Buildings	21%
Hospitals	18%
Hotels	15%
Educational Facilities	22%
Retail	18%
Supermarkets	13%
Restaurants	17%
Other Government Facilities	38%
Entertainment	43%
Source: Summit Blue 2008a	

Table 37 displays the input data and results. In summary, the commercial sector results reveal that a medium scenario reduction of 232MW is possible by 2015 (with 86 MW possible by the low scenario, and 428 MW by the high). By 2020, 491 MW is achievable through the medium scenario (with 184 MW possible by the low scenario, and 921 MW by the high).

Table 37. Potential Commercial Load Shed in Ohio, in Years 2015 and 2020		
INPUTS	**2015**	**2020**
Commercial Peak Demand (MW)	11,402	12,283
Load Shed Participation Rates:		
Low	10%	
Medium	20%	
High	30%	
Curtailment Rates:		
Low	15%	
Medium	20%	
High	25%	
RESULTS	**2015**	**2020**
Commercial DR load reductions (MW):		
Low	86	184
Medium	228	491
High	428	921

Figure 31 shows the resulting commercial load shed reductions possible for Ohio, from year 2010, when load reductions are expected to begin, through year 2025.

Figure 31. Potential Commercial Load Shed in Ohio (Medium Scenario)



DR programs that move towards the auto-DR concept can typically provide some load sheds that only require ten-minute notification or less. While some customer surveys have shown that most customers would prefer longer notification periods, many of these customers have not put in place the technologies to automate DR both load shed within a facility and the startup of emergency generation (ConEd 2008). The value of DR and the design of DR programs should take into account system operations. Ten-minute notice DR can be valuable in helping defer some investment in T&D. While not all customers may choose to provide ten-minute notice response, there should be an increasing number of customers that will provide this type of response in the future and programs should be designed to acquire this resource. This type of DR is often a more valuable form of DR with higher savings for the utility, and utilities are often ready to pay up to twice as much to customers for this short-notice responsiveness.

Industrial DR Potential in Ohio

A similar analysis was conducted for the industrial sector: load shed participation rates and curtailment rates were applied to industrial peak demand. A previous study found industrial participation rates to vary from 25% for facilities <300kW, to 50% for >300kW (Summit Blue 2008a). For this study, the following rates were applied to participation: Low (20%); Medium (30%); and High (40%).

Previous studies have found industrial curtailment rates to vary from 17% (Quantec 2007), to 30% (Consortium 2004), to 75% (Nordham 2007), resulting in a mean of 41%. The following conservative rates were applied to curtailment for this study: Low (20%); Medium (30%); and High (40%). With these participation rates and potential load curtailments, the high load reduction potential for the overall industrial sector loads is 16% (i.e., 40% participation and 40% of that load participating).

Table 38. Potential Industrial Load Shed in Ohio, for years 2015 and 2020

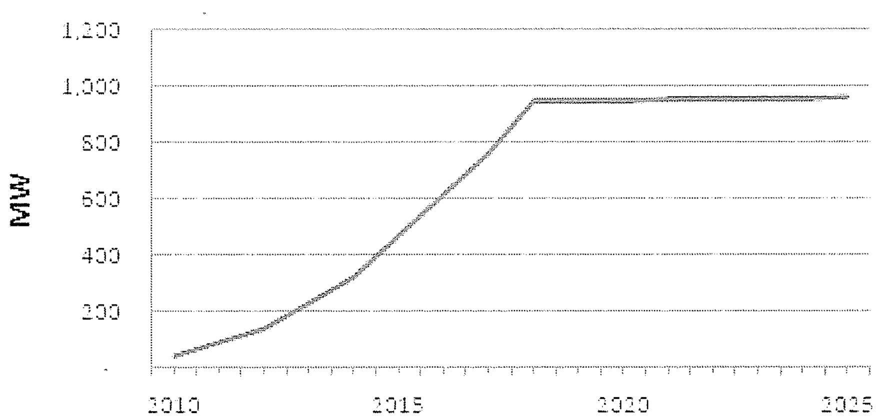
displays the input data and results. In summary, the industrial sector results reveal that a medium scenario reduction of 464 MW is possible by 2015 (with 206 MW possible by the low scenario, and 824 MW by the high). By 2020, 933 MW is achievable through the medium scenario (with 415 MW possible by the low scenario, and 1,660 MW by the high).

Table 38. Potential Industrial Load Shed in Ohio, for years 2015 and 2020

INPUTS	2015	2020
Industrial Peak Demand (MW)	10,304	10,372
Load Participation Rates:		
Low	20%	
Medium	30%	
High	40%	
Curtailment Rates:		
Low	20%	
Medium	30%	
High	40%	
RESULTS	**2015**	**2020**
Industrial DR load reductions (MW):		
Low	206	415
Medium	464	933
High	824	1,660

Figure 32 shows the resulting industrial load shed reductions possible for Ohio, from year 2010, when load reductions are expected to begin, through year 2025.

Figure 32. Potential Industrial Load Shed in Ohio (Medium Scenario)



The largest load reductions, and often the most cost-effective, may be found in Ohio's largest commercial and industrial customers. Data concerning these largest facilities were not available in Ohio so estimates are not quantified separately from the industrial analysis given in the previous section.

D.6.2. Commercial and Industrial Backup Generation Potential in OH

Emergency backup generation is a prominent component of a callable load program strategy. Some of the emergency generators not currently participating in DR programs may not be permitted for use as a DR resource and regulations may further limit the availability of emergency generation for DR. In some cases, backup generators may not be equipped with the start-up equipment to allow the generator to participate in short-term notification programs. Utilities could consider a program to assist customers with equipment specification and set-up to promote DR program participation by backup generators.

In some instances, there may be environmental restrictions on emergency generation. Emissions of emergency generation may be regulated, and the future of such regulations may add some uncertainty. However, some areas have been able to have such restrictions lifted during system emergencies.

Two approaches can increase the amount of emergency generation in DR programs: 1) facilitating customer-owned generation, and 2) utility ownership of the generation, which is used to provide additional reliability for customers willing to locate the equipment at their facilities.

Customer-Owned Emergency Generation

To increase customer-owned emergency generation, utilities may assist customers with ownership of grid-synchronized emergency generation. Utilities may offer to pay for all equipment necessary for parallel interconnection with the utility grid, as well as all maintenance and fuel expenses. Once operational, the standby generators can be monitored and dispatched from a utility's control center, and they can also provide backup power during an outage. An additional benefit to the customer relative to typical backup generation is the seamless transition to and from the generator without the usual momentary power interruption.

Utility-Owned Emergency Generation

A second approach to increasing the availability of emergency generation for DR is by locating generation at customer sites that can be owned by a utility. Through this type of program, the customer receives emergency generation capability during system outages in exchange for paying a monthly fee consisting of both levelized capital costs and operation and maintenance costs. Participants would likely receive capacity payments ($/kW-month) and/or energy payments ($/kWh) in exchange for granting a utility to dispatch the units for a limited number of events and total hours per year.

Backup Generation in Ohio

Total Ohio back-up generation capacity for 2015 is estimated at approximately 2,618 MW.[65] Additional analysis revealed that the commercial and industrial back-up capacity, each, is almost half of the total capacity, 1,309 MW.[66] Assuming a medium scenario that 40% of the total backup in Ohio is available for load shed, then 524 MW of backup generation is available by 2015 and 1,089 MW is available by 2020 (see

[65] Back-up generation capacity in Ohio was estimated from form EIA-861 filings submitted by utilities nationwide (EIA, 2006). However, only utilities providing approximately one-quarter of total kWh report these numbers. It was assumed that the prevalence and usage of distributed generation in the remaining 75% of utilities is similar.

[66] The analysis first determined the back-up generator population nation-wide, and then scaled the data down to the New England region (CBECS resolution), accounting for proportional differences in building stock nation-wide and region-wide. The region-wide results were then scaled down to Ohio specifically using the ratio of Ohio population to regional population.

Table 39. Potential Reductions from C&I Backup Generation in Ohio, in Years 2015 and 2020a

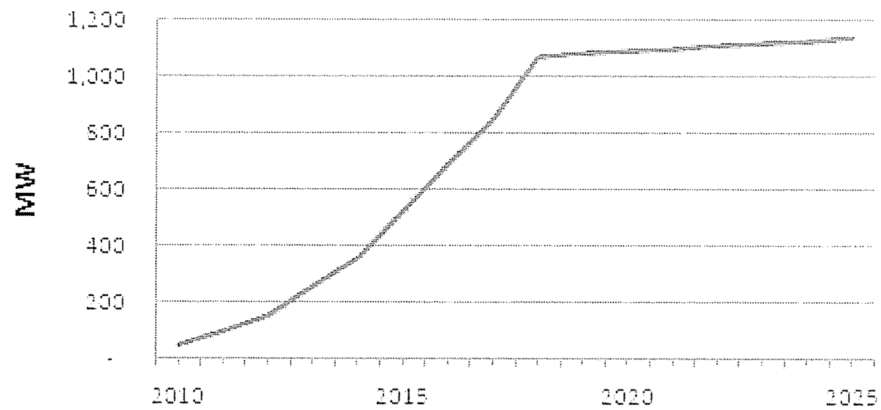
). The low scenario estimates a 393 MW reduction by 2015 and an 817 MW reduction by 2020. The high scenario estimates a 655 MW reduction by 2015 and a 1,361 MW reduction by 2020.

Table 39. Potential Reductions from C&I Backup Generation in Ohio, in Years 2015 and 2020[a]

INPUTS	2015	2020
Total Backup Generation Capacity in OH (MW)	2,618	2,722
Backup Generation Potential (%):		
Low	30%	
Medium	40%	
High	50%	
RESULTS	**2015**	**2020**
Potential Reduction from C&I Backup Generation (MW):		
Low	393	817
Medium	524	1,089
High	655	1,361

Figure 33 shows the resulting commercial and industrial backup generation reductions possible for Ohio, from year 2010, when load reductions are expected to begin, through year 2025.

Figure 33. Potential Reductions from C&I Backup Generation



D.6.3. Pricing and Rates

In this assessment of DR potential, the focus is on the use of direct load control and curtailable load response programs callable by the utility. Studies have shown that pricing programs, specifically dispatchable pricing programs such as critical peak pricing (CPP) programs can provide similar impacts; however, for the purposes of this assessment, a focus on the these load response programs is believed to be able to fully represent the DR potential, even though pricing programs could be used instead of these curtailable load programs with equal, or in some cases, greater efficiency.

New rates may be introduced as part of a DR program, and may include real-time prices, or other time-differentiated rates, for commercial and industrial customers, and a modification of any existing residential time-of-use (TOU) rates. Any new rate structures would be designed to reduce system demand during peak periods and provide an opportunity for customers to reduce electric bills through load shifting.

Critical peak pricing (CPP) is a viable option for inclusion in a DR portfolio. In FERC's 2006 survey of utilities offering DR programs (citation below), roughly 25 entities reported offering at least one CPP tariff. However, many of the tariffs were pilot programs only, and almost all of the 11,000 participants were residential customers. The apparent lack of commercial CPP programs is supported by a 2006 survey of pricing and DR programs commissioned by the U.S. EPA (below), which found only four large-customer CPP programs, all of them in California. The pilot programs in California linked the CPP rate with "automated demand response" technologies that provide most of the impact. The CPP rate itself, and the price incentive that it creates, is not the driver behind the load reductions.

As stated, rate pricing options were not analyzed in this analysis. Event-based pricing programs achieve impacts very similar to the callable load programs presented above. Pilot studies and tariff evaluations of TOU-CPP programs[67] show the load reductions for called events are similar in magnitude to air conditioning DLC programs. This is not surprising in that most TOU-CPP participants use a programmable-automated thermostat to respond to CPP events in a manner similar to a DLC strategy. One difference is that the customer response is less under the control of the program or system operator that could change cycling strategies or thermostat set points across different events or different hours within an event. Similarly, demand-bid programs are simply calls for target load sheds, i.e., those bid into the program.

In general, the direct load shed programs seem to provide greater MW of participation and more reliable reductions. However, the use of either TOU-CPP or a demand-bid program represents a point of view or policy position that price should be a centerpiece of the DR effort and help customers see prices in the electricity markets. From a point of view of simplicity and attaining firm capacity reductions, the direct load shed programs may offer some advantages. Ultimately, the choice between these direct load shed programs and pricing programs may come down to customer preferences and decisions by policy makers on the emphasis of DR efforts.

A time-differentiated rate is another option to consider that may not be "callable." Such rates include day-ahead real-time pricing (RTP), two-part RTP tariffs, and standard TOU rates. Although they are not "callable" in that the rate is generally in effect every day, there may be synergies between time-differentiated rates and callable load programs. In general, an RTP option will result in customers learning how to reduce energy consumption on essentially a daily basis when prices tend to be high (e.g., summer season afternoons and early evenings). Customers do not tend to track exact hourly prices, but they know when prices are likely to be higher (e.g., summer season afternoons with higher prices on hot days).[68] The benefits to the customer come from reducing consumption across many summer days when prices are high, rather than a focus on reduction during system event days. In general, the reductions on system peak days are roughly the same as on any summer day when prices are reasonably high. As a result, an RTP option can provide substantial benefits by increasing overall market and system efficiency through shifting loads from high priced periods to periods with lower prices. However, these tariffs may not provide the needed load relief on system-constrained event days.[69, 70]

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[67] See Public Service Electric and Gas Company, "Evaluation of the MyPower Pricing Pilot Program," prepared by Summit Blue Consulting, 2007; and the California Energy Commission, "Impact evaluation of the California Statewide Pricing Pilot—Final Report," March 16, 2005. http://www.energy.ca.gov/demandresponse/documents/index.htmll#group3

[68] See evaluations of the hourly pricing experiment offered by ComEd and the Chicago Energy Cooperative performed by Summit Blue Consulting (2003 through 2006).

[69] One way to make an RTP tariff more like an event-based DR program is to overlay a critical peak pricing (CPP) component on the RTP tariff where unusually high prices would be posted to customers with some notification period. Otherwise, it is unlikely that the high levels of reduction needed for system-event days would be attained.

[70] The complementary of event-based load shed programs with RTP tariffs is assessed in: Violette, D., R. Freeman, and C. Neil. "*DR Valuation and Market Analysis—Volume II: Assessing the DR Benefits and Costs*," Prepared for the International Energy Agency, TASK XIII, Demand-Side Programme, Demand Response Resources, January 6, 2006. Updated results are presented in: Violette, D. and R. Freeman; "*Integrating Demand Side Resource Evaluations in Resource Planning*;" Proceedings of the International Energy Program Evaluation Conference (IEPEC), Chicago, August 2007 (also at www.IEPEC.com).

Summary of DR Potential Estimates in Ohio

Table 40 shows the resulting load shed reductions possible for Ohio, by sector, for years 2015, 2020, and 2025. Load impacts grow rapidly through 2018 as program implementation takes hold. After 2018, the program impacts increase at the same rate as the forecasted growth in peak demand.

The high scenario DR load potential reduction is within a range of reasonable outcomes in that it has an eleven year rollout period (beginning of 2010 through the end of 2020), providing a relatively long period of time to ramp up and integrate new technologies that support DR. A value nearer to the high scenario than the medium scenario would make a good MW target for a set of DR activities.

The high scenario results show a reduction in peak demand of 3,078 MW is possible by 2015 (8.4% of peak demand); 6,293 MW is possible by 2020 (16.4% of peak demand); and 6,471 MW is possible by 2025 (16.2% of peak demand).

The more conservative medium scenario results show a reduction in peak demand of 2,052MW is possible by 2015 (5.6% of peak demand); 4,193MW is possible by 2020 (11.0% of peak demand); and 4,309 MW is possible by 2025 (10.8% of peak demand).

These estimated reductions in peak demand are within a range to be expected for a population of Ohio's size. Estimates of DR in other states show that the estimates calculated here for Ohio are reasonable: 15% reductions in peak demand in Florida are possible by 2023 (Elliot et al. 2007a), and 13% are possible in Texas, also by year 2023 (Elliot et al. 2007b). DR potential for a utility in New York was estimated to be 9.3% of peak demand in 2017 (Summit Blue 2008a). This finding is similar to that of a recent analysis estimating that peak load reductions from DR in the Northeast will be 8.2% of system peak load in 2020 and more than 11% by 2030 (EPRI and EEI 2008). Estimation methods differ among the studies, but nonetheless show that the 10.8% reductions in Ohio are realistic for the medium scenario by 2020.

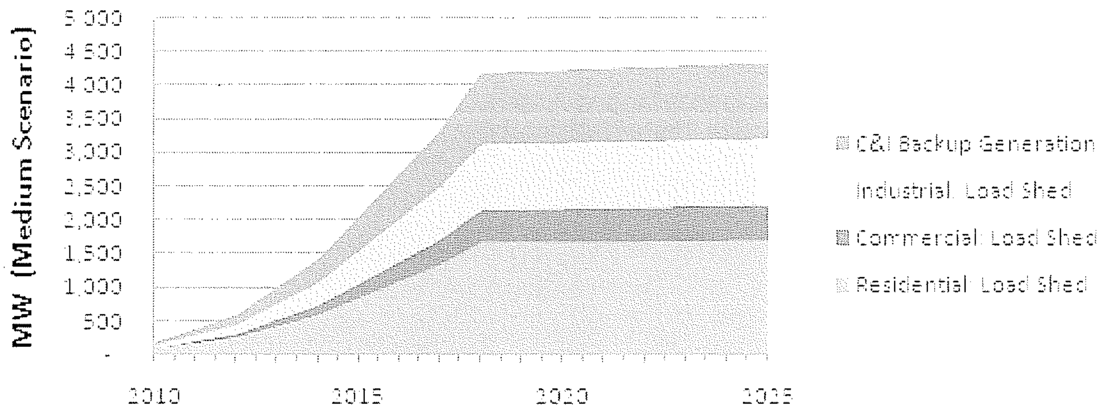
Table 40. Summary of Potential DR in Ohio, By Sector, for Years 2015, 2020, and 2025[a]

	Low Scenario			Medium Scenario			High Scenario		
	2015	**2020**	**2025**	**2015**	**2020**	**2025**	**2015**	**2020**	**2025**
Load Sheds (MW):									
Residential	502	1,008	1,017	837	1,680	1,696	1,172	2,352	2,374
Commercial	86	184	199	228	491	531	428	921	996
Industrial	206	415	420	464	933	944	824	1,660	1,678
C&I Backup Generation (MW)	393	817	854	524	1,089	1,138	655	1,361	1,423
Total DR Potential (MW)	1,186	2,424	2,490	2,052	4,193	4,309	3,078	6,293	6,471
DR Potential as % of Total Peak Demand	3.2%	6.4%	6.3%	5.6%	11.0%	10.8%	8.4%	16.4%	16.2%

a. See Section 3 for underlying data and assumptions.

Figure 34 shows the resulting load shed reductions possible for Ohio, by sector, from year 2010, when load reductions are expected to begin, through year 2025.

Figure 34. Potential DR Load Reductions in Ohio by Sector (MW)



These estimates reflect the level of effort put forth and utilities are recommended to set targets for the high scenarios. These estimates include assumptions based on utility experience regarding growth rates, participation rates, and program design, among others, and will adjust accordingly if differing assumptions are made. The assumptions made are believed to be conservative, and reflect minimum achievable DR potential. For example, participation rates for all of the sectors are based on experience in other states, and are based primarily on customer awareness, the ability to have automated response, and the adequacy of reward. If the statewide education program now required in Ohio promotes DR programs and adequate incentives are offered, then participation rates higher than the medium scenario are entirely realistic.

Recommendations

This assessment indicates that the system peak demand can be reduced by approximately 11.0% or 4,193 MW in 2020 in the medium case. In the high case, the reduction can be as high as 16.4% or 6,293 MW. The high case is considered to be within a reasonable range if aggressive action begins by the end of 2009, providing for a twelve-year rollout of the DR efforts (at the beginning of 2010 through the end of 2020).

Key recommendations include:

- Implement programs focused on achieving firm capacity reductions as this provides the highest value demand response. This is accomplished through establishing appropriate customer expectations and by conducting program tests for each DR program in each year. These tests should be used to establish expected DR program impacts when called and to work with customers each year to ensure that they can achieve the load reductions expected at each site.

- Appropriate financial incentives for the Ohio' utilities either for programs administered directly by the utilities or for outsourcing DR efforts to aggregators. The basic premise is that a utility's least-cost plan should also be its most profitable plan. Developing these incentives poses some complexities in that MW's in that DR programs likely will be bid into PJM's DR programs and will receive financial payments from PJM. Whether this provides adequate incentives for the appropriate development of DR programs in Ohio should be examined.

- Combine and cross-market EE and DR programs. These can include new building codes and standards that include not only EE construction and equipment, but also the installation of addressable and dispatchable equipment. This can include addressable thermostats in new residences and the installation of addressable energy management systems in commercial and industrial buildings that can reduce loads in select end-uses across the building/facility. In addition, energy audits of residential or commercial facilities can also include an assessment of whether that facility is a good candidate for participation in a DR program through the identification of dispatchable loads. Furthermore, building commissioning and retro-commissioning EE programs that are becoming popular in many commercial and industrial sector programs have the energy management system as a core component of program delivery. At this time, the application of auto-DR can be assessed and marketed to the customer along with the EE savings from these site-commissioning programs.

- Include customer education in DR efforts. There is some perceived lack of customer awareness of programs and incentives. In addition, new programs will need marketing efforts as well as technical assistance to help customers identify where load reductions can be obtained and the technologies/actions needed to achieve these load reductions. Also, high-level education on the volatility of electricity markets helps customers understand why utilities and other entities are promoting DR and the customers' role in increasing demand response to help match up with supply-side resources to achieve lower cost resource solutions when markets become tight

- Increase clarity and coordination between the Federal and State agencies and programs. While states have primary jurisdiction over retail demand response, the FERC has jurisdiction over demand response in wholesale markets. Greater clarity and coordination between the Federal and State programs is needed. At the Federal level, both EPACT and EISA contain multiple provisions on demand response and smart grid technologies. EISA authorized a matching grant program to offset the costs of Smart Grid investments.

- Understand that pricing may form the cornerstone of an efficient electric market. Daily TOU pricing and day-ahead hourly pricing will increase overall market efficiency by causing shifts in energy use from on-peak to off-peak hours every day of the year. However, this does not diminish the need to have dispatchable DR programs that can address those few days that represent extreme events where the highest demands occur. These events are best addressed by dispatchable DR programs.

APPENDIX E – COMBINED HEAT AND POWER

E.1. Technical Potential for CHP

This section provides an estimate of the technical market potential for combined heat and power (CHP) in the industrial, commercial/institutional, and multi-family residential market sectors. Two different types of CHP markets were included in the evaluation of technical potential. Both of these markets were evaluated for high load factor (80% and above) and low load factor (51%) applications resulting in four distinct market segments that are analyzed.

E.1.1. Traditional CHP

Traditional CHP electrical output is produced to meet all or a portion of the base load for a facility and the thermal energy is used to provide steam or hot water. Depending on the type of facility, the appropriate sizing could be either electric or thermal limited. Industrial facilities often have "excess" thermal load compared to their on-site electric load. Commercial facilities almost always have excess electric load compared to their thermal load. Two sub-categories were considered:

High load factor applications: This market provides for continuous or nearly continuous operation. It includes all industrial applications and round-the-clock commercial/institutional operations such colleges, hospitals, hotels, and prisons.

Low load factor applications: Some commercial and institutional markets provide an opportunity for coincident electric/thermal loads for a period of 3,500 to 5,000 hours per year. This sector includes applications such as office buildings, schools, and laundries.

E.1.2. Combined Cooling Heating and Power (CCHP)

All or a portion of the thermal output of a CHP system can be converted to air conditioning or refrigeration with the addition of a thermally activated cooling system. This type of system can potentially open up the benefits of CHP to facilities that do not have the year-round thermal load to support a traditional CHP system. A typical system would provide the annual hot water load, a portion of the space heating load in the winter months and a portion of the cooling load in during the summer months. Two sub-categories were considered:

Low load factor applications. These represent markets that otherwise could not support CHP due to a lack of thermal load.

Incremental high load factor applications: These markets represent round-the-clock commercial/institutional facilities that could support traditional CHP, but with cooling, incremental capacity could be added while maintaining a high level of utilization of the thermal energy from the CHP system. All of the market segments in this category are also included in the high load factor traditional market segment, so only the incremental capacity for these markets is added to the overall totals.

The estimation of technical market potential consists of the following elements:

- Identification of applications where CHP provides a reasonable fit to the electric and thermal needs of the user. Target applications were identified based on reviewing the electric and thermal energy consumption data for various building types and industrial facilities.
- Quantification of the number and size distribution of target applications. Several data sources were used to identify the number of applications by sector that meet the thermal and electric load requirements for CHP.
- Estimation of CHP potential in terms of megawatt (MW) capacity. Total CHP potential is

then derived for each target application based on the number of target facilities in each size category and sizing criteria appropriate for each sector.
- Subtraction of existing CHP from the identified sites to determine the remaining technical market potential.

The technical market potential does not consider screening for economic rate of return, or other factors such as ability to retrofit, owner interest in applying CHP, capital availability, natural gas availability, and variation of energy consumption within customer application/size class. The technical potential as outlined is useful in understanding the potential size and size distribution of the target CHP markets in the state. Identifying technical market potential is a preliminary step in the assessment of market penetration.

The basic approach to developing the technical potential is described below:

- *Identify existing CHP in the state.* The analysis of CHP potential starts with the identification of existing CHP. In Ohio, there are 45 operating CHP plants totaling 665 MW of capacity. Of this existing CHP capacity, 55% of the sites and 85% of the capacity are in the industrial sector. This existing CHP capacity is deducted from any identified technical potential. A summary of the existing CHP capacity by industry is shown in Table 41.

- *Identify applications where CHP provides a reasonable fit to the electric and thermal needs of the user.* Target applications were identified based on reviewing the electric and thermal energy (heating and cooling) consumption data for various building types and industrial facilities. Data sources include the DOE EIA *Commercial Buildings Energy Consumption Survey (CBECS),* the DOE *Manufacturing Energy Consumption Survey (MECS)* and various market summaries developed by DOE, Gas Technology Institute (GRI), and the American Gas Association. Existing CHP installations in the commercial/institutional and industrial sectors were also reviewed to understand the required profile for CHP applications and to identify target applications.

- *Quantify the number and size distribution of target applications.* Once applications that could technically support CHP were identified, the iMarket, Inc. *MarketPlace Database* and the *Major Industrial Plant Database* (MIPD) from IHI were utilized to identify potential CHP sites by SIC code or application, and location (county). The *MarketPlace Database* is based on the Dun and Bradstreet financial listings and includes information on economic activity (8 digit SIC), location (metropolitan area, county, electric utility service area, state) and size (employees) for commercial, institutional and industrial facilities. In addition, for select SICs limited energy consumption information (electric and gas consumption, electric and gas expenditures) is provided based on data from Wharton Econometric Forecasting (WEFA). MIPD has detailed energy and process data for 16,000 of the largest energy consuming industrial plants in the United States. The *MarketPlace Database* and MIPD were used to identify the number of facilities in target CHP applications and to group them into size categories based on average electric demand in kilowatt-hours.

- *Estimate CHP potential in terms of MW capacity.* Total CHP potential was then derived for each target application based on the number of target facilities in each size category. It was assumed that the CHP system would be sized to meet the average site electric demand for the target applications unless thermal loads (heating and cooling) limited electric capacity. Tables 42 through 44 present the specific target market sectors, the number of potential sites and the potential MW contribution from CHP. There are two distinct applications and two levels of annual load making for four market segments in all. In traditional CHP, the thermal energy is recovered and used for heating, process steam, or hot water. In cooling CHP, the system provides both heating and cooling needs for the facility. High load factor applications operate at 80% load factor and above; low load factor applications operate at an assumed average of 4500 hours per year (51%) load factor. The high load factor cooling applications are also applications for traditional CHP, though the cooling applications have 25-30% more capacity than traditional. Therefore, the totals for the entire state, all four market segments, discounts these applications to avoid double counting.

- *Estimate the growth of new facilities in the target market sectors.* The technical potential included economic projections for growth through 2025 by target market sectors in Ohio. The growth factors used in the analysis for growth between the present and 2025 by individual sector are shown in Table 45. These growth projections provided by ACEEE were used in this analysis as an estimate of the growth in new facilities. In cases where an economic sector is declining, it was assumed that no new facilities would be added to the technical potential for CHP. Based on these growth rates the total technical market potential is summarized in Table 46.

Table 41. Ohio Existing CHP Facilities

SIC	Industry Description	Sites	Cap. kW
24	Lumber and Wood Products	2	10,900
2511	Wood Household Furniture	1	1,000
26	Paper	6	151,730
28	Chemicals	6	47,425
2911	Petroleum Refining	1	6,000
30	Rubber and Plastics	2	41,900
33	Primary Metals	4	102,050
35	Industrial Machinery	1	700
37	Transportation Equipment	1	75
39	Miscellaneous Manufacturing	1	200,000
49	Utilities	4	8,625
7011	Hotels and Motels	1	100
7991	Physical Fitness Facility	1	150
80	Health Services	2	1,765
82	Educational Services	6	73,573
8412	Museums and Art Galleries	1	240
8811	Private Households	1	115
91	Executive, Legislative, General Government	3	16,615
9711	Military Base	1	2,075
	Total	45	665,038

Table 42. Ohio Technical Market Potential for CHP in Existing Facilities – Industrial Sector

SICs	Application	50-500 kW Sites	50-500 kW MW	500-1 MW Sites	500-1 MW (MW)	1-5 MW Sites	1-5 MW (MW)	5-20 MW Sites	5-20 MW (MW)	>20 MW Sites	>20 MW (MW)	Total Sites	Total MW
Industrial (Traditional, High Load Factor													
20	Food	242	36.3	90	67.5	62	155.0	21	262.5	3	225.0	418	746.3
22	Textiles	43	4.8	12	6.8	2	3.8	0	0.0	0	0.0	57	15.3
24	Lumber and Wood	234	7.0	31	4.7	10	5.0	2	5.0	1	15.0	278	36.7
25	Furniture	21	0.9	2	0.5	0	0.0	0	0.0	0	0.0	23	1.4
26	Paper	173	26.0	107	80.3	89	222.5	2	25.0	0	0.0	371	353.7
27	Printing/Publishing	121	18.2	5	3.8	0	0.0	0	0.0	0	0.0	126	21.9
28	Chemicals	254	38.1	108	81.0	135	337.5	37	462.5	22	1,650.0	556	2,569.1
29	Petroleum Refining	128	19.2	11	8.3	6	15.0	0	0.0	0	0.0	145	42.5
30	Rubber/Misc. Plastics	361	16.2	339	76.3	203	152.3	31	116.3	0	0.0	934	361.0
32	Stone/Clay/Glass	14	2.1	6	4.5	1	2.5	1	12.5	3	225.0	25	246.6
33	Primary Metals	80	3.0	56	10.5	45	28.1	5	15.6	1	18.8	187	76.0
34	Fabricated Metals	409	18.4	88	19.8	41	30.8	0	0.0	0	0.0	538	69.0
35	Machinery/Computer Equip	23	0.9	1	0.2	4	2.5	0	0.0	0	0.0	28	3.6
37	Transportation Equip.	98	7.4	69	25.9	106	132.5	29	181.3	13	487.5	315	834.5
38	Instruments	21	1.6	3	1.1	0	0.0	0	0.0	0	0.0	24	2.7
39	Misc. Manufacturing	26	1.0	5	0.9	1	0.6	0	0.0	0	0.0	32	2.5
	Total Industrial	2248	201.0	933	391.8	705	1,088.0	128	1,080.6	43	2,621.3	4057	5,382.7

Table 43. Ohio Technical Market Potential for CHP in Existing Facilities – Commercial, Traditional CHP

SICs	Application	50-500 kW Sites	50-500 kW MW	500-1 MW Sites	500-1 MW (MW)	1-5 MW Sites	1-5 MW (MW)	5-20 MW Sites	5-20 MW (MW)	>20 MW Sites	>20 MW (MW)	Total Sites	Total MW
Commercial, Multifamily(Traditional, High Load Factor)													
6513	Apartments	381	28.6	138	51.8	21	26.3					540	106.6
4222, 5142	Warehouses	15	2.3	22	16.5	5	12.5					42	31.3
4941, 4952	Water Treatment/Sanitary	103	15.5	71	53.3	33	82.5	1	12.5			208	163.7
7011, 7041	Hotels	893	100.5	169	95.1	34	63.8					1096	259.3
8051, 8052, 8059	Nursing Homes	664	99.6	388	291.0	32	80.0					1084	470.6
8062, 8063, 8069	Hospitals	106	15.9	59	44.3	128	320.0	3	37.5			296	417.7
8221, 8222	Colleges/Universities	106	15.9	80	60.0	54	135.0	16	200.0	2	50.0	258	460.9
9223, 9211 (Courts), 9224 (firehouses)	Prisons	10	1.5	31	23.3	38	95.0	8	100.0			87	219.8
	Total C/I High LF	2278	279.6	958	635.1	345	815.0	28	350.0	2	50.0	3611	2,129.7
Commercial (Traditional, Low Load Factor)													
7211, 7213, 7218	Laundries	71	10.7	2	1.5							73	12.2
7542	Carwashes	113	17.0									113	17.0
7991, 00, 01	Health Clubs	144	21.6	19	14.3							163	35.9
7992, 7997-9904, 7997-9906	Golf/Country Clubs	328	49.2	25	18.8							353	68.0
8211, 8243, 8249, 8299	Schools	1227	46.0	233	43.7	23	14.4	4	12.5			1487	116.6
8412	Museums	60	9.0	10	7.5							70	16.5
	Total C/I Low LF	1943	153.4	289	85.7	23	14.4	4	12.5			2259	266.0
	Total C/I Traditional	4221	433.1	1247	720.8	368	829.4	32	362.5	2	50.0	5870	2,395.7

Table 44. Ohio Technical Market Potential for CHP in Existing Facilities – Commercial, Cooling

SICs	Application	50-500 kW Sites	50-500 kW MW	500-1 MW Sites	500-1 MW (MW)	1-5 MW Sites	1-5 MW (MW)	5-20 MW Sites	5-20 MW (MW)	>20 MW Sites	>20 MW (MW)	Total Sites	Total MW
Commercial Cooling, High Load Factor													
7011, 7041	Hotels- Cooling	894	134.1	169	126.75	34	85.0					1097	345.9
8051, 8052, 8059	Nursing Homes- Cooling	664	119.5	388	349.2	32	96.0					1084	564.7
8062, 8063, 8069	Hospitals- Cooling	106	19.1	60	54	129	387.0	3	45.0			298	505.1
	Total Cooling High LF	1664	272.7	617	529.95	195	568.0	3	45.0			2479	1,415.7
Commercial Cooling, Low Load Factor													
5411, 5421, 5451, 5461, 5499	Food Sales	1619	121.4	232	87.0	20	25.0					1871	233.4
5812, 00, 01, 03, 05, 07, 08	Restaurants	2402	180.2	15	5.6							2417	185.8
43	Post Offices	189	28.4									189	28.4
4581	Airports	17	2.6	1	0.8							18	3.3
52,53,56,57	Big Box Retail	1252	187.8	304	228.0	105	262.5					1661	678.3
7832	Movie Theaters	71	10.7									71	10.7
6512	Office Buildings - Cooling	2773	208.0	1213	454.875	347	433.8					4333	1,096.6
	Total Cooling Low LF	8323	738.9	1765	776.25	472	721.3					10560	2,236.4
	Total Cooling	9987	1,011.6	2382	1306.2	667	1,289.3	3	45.0			13039	3,652.1
	Total C/I All Types	12544	1,253.8	3012	1,656.0	840	1,721.0	32	376.0	2	50.0	16430	3,491.3

Note: High Load factor cooling adds only 30% to the total C/I MW potential because the sites are already included in High LF Traditional. The 30% represents the incremental capacity offered by adding cooling.

Table 45. Ohio Sector Growth Projections Through 2025

SIC Code	Market Sector	2008-2025 Real Growth
20	Food	14.6%
22	Textiles	2.6%
24	Lumber and Wood	15.4%
25	Furniture	15.4%
26	Paper	15.4%
27	Printing/Publishing	2.6%
28	Chemicals	71.7%
29	Petroleum Refining	71.7%
30	Rubber/Misc. Plastics	71.7%
32	Stone/Clay/Glass	39.8%
33	Primary Metals	28.4%
34	Fabricated Metals	28.4%
35	Machinery/Computer Equip	67.5%
37	Transportation Equip.	43.9%
38	Instruments	28.8%
39	Misc. Manufacturing	15.4%
43	Post Offices	15.6%
4581	Airports	15.6%
6512	Office Buildings - Cooling	0.0%
6513	Apartments	0.0%
7542	Carwashes	0.0%
7832	Movie Theaters	17.6%
8412	Museums	17.6%
4222, 5142	Warehouses	77.6%
4941, 4952	Water Treatment/Sanitary	20.6%
52,53,56,57	Big Box Retail	25.1%
5411, 5421, 5451, 5461, 5499	Food Sales	25.1%
5812, 00, 01, 03, 05, 07, 08	Restaurants	17.6%
7011, 7041	Hotels	17.6%
7011, 7041	Hotels- Cooling	17.6%
7211, 7213, 7218	Laundries	0.0%
7991, 00, 01	Health Clubs	17.6%
7992, 7997-9904, 7997-9906	Golf/Country Clubs	17.6%
8051, 8052, 8059	Nursing Homes	2.0%
8051, 8052, 8059	Nursing Homes- Cooling	2.0%
8062, 8063, 8069	Hospitals	2.0%
8062, 8063, 8069	Hospitals- Cooling	2.0%
8211, 8243, 8249, 8299	Schools	2.0%
8221, 8222	Colleges/Universities	2.0%
9223, 9211 (Courts), 9224 (firehouses)	Prisons	0.1%

Table 46. CHP Market Segments, Ohio Existing Facilities and Expected Growth 2008-2025

Market	50-500 kW MW	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total MW
Traditional High Load Factor Market						
Existing Facilities	481	1,027	1,903	1,287	2,975	7,672
New Facilities	251	542	985	673	1,865	4,316
Total	732	1,569	2,888	1,960	4,840	11,988
Traditional Low Load Factor Market						
Existing Facilities	153	86	14	13	0	266
New Facilities	86	50	7	6	0	149
Total	239	136	21	19	0	415
Cooling CHP High Load Factor Market (partially additive)						
Existing Facilities	273	530	568	45	0	1,416
New Facilities	158	285	295	15	0	752
Total	430	815	863	60	0	2,168
Cooling CHP Low Load Factor Market						
Existing Facilities	739	776	721	0	0	2,236
New Facilities	529	518	478	0	0	1,524
Total	1,268	1,294	1,199	0	0	3,760
Total Market including Incremental Cooling Load						
Existing Facilities	1,455	2,048	2,809	1,313	2,975	10,600
New Facilities	913	1,195	1,558	683	1,865	6,215
Total	2,368	3,243	4,367	1,997	4,840	16,814

Note: High load factor cooling market is comprised of a portion of the traditional high load factor market that has both heating and cooling loads. The total high load factor cooling market is shown, but only 30% of it is incremental to the portion already counted in the traditional high load factor market. Growth rates were extrapolated for the 2020-2025 market penetration forecast.

E.2. Energy Price Projections

The expected future relationship between purchased natural gas and electricity prices, called the *spark spread* in this context, is one major determinant of the ability of a facility with electric and thermal energy requirements to cost-effectively utilize CHP. For this screening analysis, a fairly simple methodology was used:

E.2.1. Electric Price Estimation

- Retail electric price forecasts EIA's Annual Energy Forecast for 2007 were used as the starting point for the analysis. ACEEE provided state by state estimates. The annual price forecasts provided were converted to 5 year averages for use in the market penetration model. These prices are shown in **Table E-7**.
- The electricity price assumptions for the high load factor CHP applications were as follows

  - 50-500 kW – Commercial average price
  - 500 kW to 5 MW – Industrial average price
  - 5 MW and above – 90% of industrial average price
- Price adjustments for customer load factor were defined as follows:
  - High load factor – 100% of the estimated value
  - Low load factor – 120% of the estimated value
  - Peak cooling load – 150% of the estimated value
- For a customer generating a portion of his own power with CHP, standby charges are estimated at 15% of the defined average electric rate. Therefore, when considering CHP, only 85% of a customer's rate can be avoided.

E.2.2. Natural Gas Price Estimation

- The natural gas price assumptions are based on the industrial retail price shown in the table.
  - All customer boiler fuel is assumed at the industrial rate except for the CHP market below 500 kW where the boiler gas price is assumed to be $0.50/MMBtu higher
  - All CHP fuel is assumed to be at a $0.60/MMBt discount to the retail industrial price.

Table 47. Input Price Forecast (EIA-AEO 2007) and Ohio Industrial Electric Price Estimation

Ohio Energy Prices	Avg. 2007-2009	Avg.2010-2014	Avg.2015-2019	Avg.2020-2024
Ohio Retail Electricity Prices (2006$/kWh)				
Residential	$0.091	$0.101	$0.116	$0.126
Commercial	$0.083	$0.094	$0.106	$0.117
Industrial	$0.056	$0.067	$0.080	$0.089
Ohio Retail Natural Gas Prices (2006$/MMbtu)				
Residential	$13.729	$12.531	$12.782	$13.262
Commercial	$12.135	$10.709	$10.829	$11.193
Industrial	$10.813	$9.046	$9.209	$9.662

E.3. CHP Technology Cost and Performance

The CHP system itself is the engine that drives the economic savings. The cost and performance characteristics of CHP systems determine the economics of meeting the site's electric and thermal loads. A representative sample of commercially and emerging CHP systems was selected to profile performance and cost characteristics in combined heat and power (CHP) applications. The selected systems range in capacity from approximately 100 – 20,000 kW. The technologies include gas-fired reciprocating engines, gas turbines, microturbines and fuel cells. The appropriate technologies were allowed to compete for market share in the penetration model. In the smaller market sizes, reciprocating engines competed with microturbines and fuel cells. In intermediate sizes (1 to 20 MW), reciprocating engines competed with gas turbines.

Cost and performance estimates for the CHP systems were based on work being undertaken for the EPA.[71] The foundation for these updates is based on work previously conducted for NYSERDA,[72] on

[71] EPA CHP Partnership Program, Technology Characterizations, December 2007 (under review).

peer-reviewed technology characterizations that Energy and Environmental Analysis (EEA) developed for the National Renewable Energy Laboratory (NREL 2003) and on follow-on work conducted by DE Solutions for Oak Ridge National Laboratory (ORNL 2004). Additional emissions characteristics and cost and performance estimates for emissions control technologies were based on ongoing work EEA is conducting for EPRI (EPRI 2005). Data is presented for a range of sizes that include basic electrical performance characteristics, CHP performance characteristics (power to heat ratio), equipment cost estimates, maintenance cost estimates, emission profiles with and without after-treatment control, and emissions control cost estimates. The technology characteristics are presented for three years: 2005, 2010, 2020. The 2007-2010 estimates are based on current commercially available and emerging technologies. The cost and performance estimates for 2010-2015 and 2015-2020 reflect current technology development paths and currently planned government and industry funding. These projections were based on estimates included in the three references mentioned above. NOx, CO and VOC emissions estimates in lb/MWh are presented for each technology both with and without aftertreatment control (AT). For this analysis, aftertreatment was only included for the 800 kW and 3000 kW engines. The installed costs in Tables 48 through 51 are based on typical national averages.

[72] *Combined Heat and Power Potential for New York State*, Energy Nexus Group (later became part of EEA), for NYSERDA, May 2002.

Table 48. Reciprocating Engine Cost and Performance Characteristics

CHP System	Characteristic/Year Available	2007-2010	2010-2015	2016-2020
100 kW	Installed Costs, $/kW	$2,210	$1,925	$1,568
	Heat Rate, Btu/kWh	12,000	10,830	10,500
	Electric Efficiency, %	28.4%	31.5%	32.5%
	Thermal Output, Btu/kWh	6100	5093	4874
	O&M Costs, $/kWh	0.022	0.013	0.012
	NOx Emissions, lbs/MWh (w/ AT)	0.10	0.15	0.15
	CO Emissions w/AT, lb/MWh	0.32	0.60	0.30
	VOC Emissions w/AT, lb/MWh	0.10	0.09	0.05
	PMT 10 Emissions, lb/MWh	0.11	0.11	0.11
	SO_2 Emissions, lb/MWh	0.0068	0.0064	0.0062
	After-treatment Cost, $/kW	incl.	incl.	incl.
800 kW	Installed Costs, $/kW	$1,640	$1,443	$1,246
	Heat Rate, Btu/kWh	9,760	9,750	9,225
	Electric Efficiency, %	35.0%	35.0%	37.0%
	Thermal Output, Btu/kWh	2313	3791	3250
	O&M Costs, $/kWh	0.013	0.01	0.009
	NOx Emissions, lbs/MWh (w/ AT)	0.5	1.24	0.93
	CO Emissions w/AT, lb/MWh	1.87	0.45	0.31
	VOC Emissions w/AT, lb/MWh	0.47	0.05	0.05
	PMT 10 Emissions, lb/MWh	0.10	0.01	0.01
	SO_2 Emissions, lb/MWh	0.0068	0.0057	0.0054
	After-treatment Cost, $/kW	300	190	140
3000 kW	Installed Costs, $/kW	$1,130	$1,100	$1,041
	Heat Rate, Btu/kWh	9,492	8,750	8,325
	Electric Efficiency, %	35.9%	39.0%	41.0%
	Thermal Output, Btu/kWh	3510	3189	2982
	O&M Costs, $/kWh	0.011	0.0083	0.008
	NOx Emissions, lbs/MWh (w/ AT)	1.52	1.24	0.775
	CO Emissions w/AT, lb/MWh	0.78	0.31	0.31
	VOC Emissions w/AT, lb/MWh	0.34	0.10	0.10
	PMT 10 Emissions, lb/MWh	0.01	0.01	0.01
	SO_2 Emissions, lb/MWh	0.0057	0.0051	0.0049
	After-treatment Cost, $/kW	200	130	100
5000 kW	Installed Costs, $/kW	$1,130	$1,099	$1,038
	Heat Rate, Btu/kWh	8,758	8,325	7,935
	Electric Efficiency, %	39.0%	41.0%	43.0%
	Thermal Output, Btu/kWh	3046	2797	2605
	O&M Costs, $/kWh	0.009	0.008	0.008
	NOx Emissions, lbs/MWh (w/ AT)	1.55	1.24	0.775
	CO Emissions w/AT, lb/MWh	0.75	0.31	0.31
	VOC Emissions w/AT, lb/MWh	0.22	0.10	0.10
	PMT 10 Emissions, lb/MWh	0.01	0.01	0.01
	SO_2 Emissions, lb/MWh	0.0054	0.0049	0.0047
	After-treatment Cost, $/kW	150	115	80

Table 49. Microturbine Cost and Performance Characteristics

CHP System	Characteristic/Year Available	2007-2010	2010-2015	2016-2020
60 kW	Installed Costs, $/kW	$2,739	$2,037	$1,743
	Heat Rate, Btu/kWh	13,891	12,500	11,375
	Electric Efficiency, %	24.6%	27.3%	30.0%
	Thermal Output, Btu/kWh	6308	3791	3102
	O&M Costs, $/kWh	0.022	0.016	0.012
	NOx Emissions, lbs/MWh (w/ AT)	0.15	0.14	0.13
	CO Emissions w/AT, lb/MWh	0.24	0.22	0.20
	VOC Emissions w/AT, lb/MWh	0.03	0.03	0.02
	PMT 10 Emissions, lb/MWh	0.22	0.20	0.19
	SO_2 Emissions, lb/MWh	0.0079	0.0074	0.0067
	After-treatment Cost, $/kW			
250 KW	Installed Costs, $/kW	$2,684	$2,147	$1,610
	Heat Rate, Btu/kWh	13,080	11,750	10,825
	Electric Efficiency, %	2.6%	29.0%	31.5%
	Thermal Output, Btu/kWh	4800	3412	2625
	O&M Costs, $/kWh	0.015	0.013	0.012
	NOx Emissions, lbs/MWh (w/ AT)	0.43	0.24	0.13
	CO Emissions w/AT, lb/MWh	0.26	0.26	0.24
	VOC Emissions w/AT, lb/MWh	0.03	0.03	0.02
	PMT 10 Emissions, lb/MWh	0.18	0.18	0.16
	SO_2 Emissions, lb/MWh	0.0070	0.0069	0.0064
	After-treatment Cost, $/kW	500	200	90

Table 50. Fuel Cell Cost and Performance Characteristics

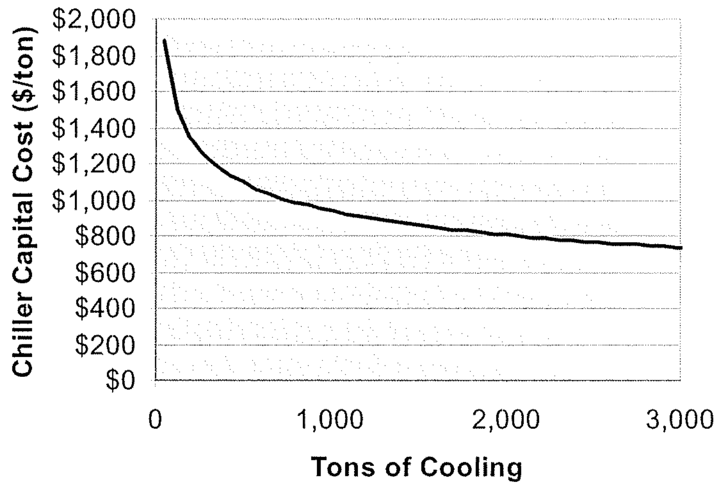
CHP System	Characteristic/Year Available	2007-2010	2010-2015	2016-2020
200 kW PAFC in 2005 150 kW PEMFC in outyears	Installed Costs, \$/kW	\$6,310	\$4,782	\$3,587
	Heat Rate, Btu/kWh	9,480	9,480	8,980
	Electric Efficiency, %	36.0%	36.0%	38.0%
	Thermal Output, Btu/kWh	4250	3482	3281
	O&M Costs, \$/kWh	0.038	0.017	0.015
	NOx Emissions, lbs/MWh (w/ AT)	0.06	0.05	0.04
	CO Emissions w/AT, lb/MWh	0.07	0.07	0.07
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.00	0.00	0.00
	SO_2 Emissions, lb/MWh	0.0057	0.0056	0.0053
	After-treatment Cost, \$/kW	n.a.	n.a.	n.a.
300 kW MCFC	Installed Costs, \$/kW	\$5,580	\$4,699	\$3,671
	Heat Rate, Btu/kWh	8,022	7,125	6,920
	Electric Efficiency, %	42.5%	47.9%	49.3%
	Thermal Output, Btu/kWh	1600	1723	1602
	O&M Costs, \$/kWh	0.035	0.02	0.015
	NOx Emissions, lbs/MWh (w/ AT)	0.1	0.05	0.04
	CO Emissions w/AT, lb/MWh	0.07	0.05	0.04
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.00	0.00	0.00
	SO_2 Emissions, lb/MWh	0.0057	0.0042	0.0041
	After-treatment Cost, \$/kW	n.a.	n.a.	n.a.
1200 kW MCFC	Installed Costs, \$/kW	\$5,250	\$4,523	\$3,554
	Heat Rate, Btu/kWh	8,022	7,110	6,820
	Electric Efficiency, %	42.5%	48.0%	50.0%
	Thermal Output, Btu/kWh	1583	1706	1503
	O&M Costs, \$/kWh	0.032	0.019	0.015
	NOx Emissions, lbs/MWh (w/ AT)	0.05	0.05	0.04
	CO Emissions w/AT, lb/MWh	0.04	0.04	0.03
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.00	0.00	0.00
	SO_2 Emissions, lb/MWh	0.0044	0.0042	0.0040
	After-treatment Cost, \$/kW	n.a.	n.a.	n.a.

Table 51. Gas Turbine Cost and Performance Characteristics

CHP System	Characteristic/Year Available	2007-2010	2010-2015	2016-2020
3000 KW GT	Installed Costs, $/kW	$1,690	$1,560	$1,300
	Heat Rate, Btu/kWh	13,100	12,650	11,200
	Electric Efficiency, %	26.0%	27.0%	30.5%
	Thermal Output, Btu/kWh	5018	4489	4062
	O&M Costs, $/kWh	0.0074	0.0065	0.006
	NOx Emissions, lbs/MWh (w/ AT)	0.68	0.38	0.2
	CO Emissions w/AT, lb/MWh	0.55	0.53	0.47
	VOC Emissions w/AT, lb/MWh	0.03	0.03	0.02
	PMT 10 Emissions, lb/MWh	0.21	0.20	0.18
	SO_2 Emissions, lb/MWh	0.0070	0.0069	0.0069
	After-treatment Cost, $/kW	210	175	150
10 MW GT	Installed Costs, $/kW	$1,298	$1,342	$1,200
	Heat Rate, Btu/kWh	11,765	10,800	9,950
	Electric Efficiency, %	29.0%	31.6%	34.3%
	Thermal Output, Btu/kWh	4674	4062	3630
	O&M Costs, $/kWh	0.007	0.006	0.005
	NOx Emissions, lbs/MWh (w/ AT)	0.67	0.37	0.2
	CO Emissions w/AT, lb/MWh	0.50	0.46	0.42
	VOC Emissions w/AT, lb/MWh	0.02	0.02	0.02
	PMT 10 Emissions, lb/MWh	0.20	0.18	0.17
	SO_2 Emissions, lb/MWh	0.0069	0.0064	0.0059
	After-treatment Cost, $/kW	140	125	100
40 MW GT	Installed Costs, $/kW	$972	$944	$916
	Heat Rate, Btu/kWh	9,220	8,865	8,595
	Electric Efficiency, %	37.0%	38.5%	39.7%
	Thermal Output, Btu/kWh	3189	3019	2892
	O&M Costs, $/kWh	0.004	0.004	0.004
	NOx Emissions, lbs/MWh (w/ AT)	0.55	0.2	0.1
	CO Emissions w/AT, lb/MWh	0.04	0.04	0.04
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.16	0.15	0.15
	SO_2 Emissions, lb/MWh	0.0054	0.0052	0.0051
	After-treatment Cost, $/kW	90	75	40

In the cooling markets, an additional cost was added to reflect the costs of adding chiller capacity to the CHP system. These costs depend on the sizing of the absorption chiller which in turn depends on the amount of usable waste heat that the CHP system produces. Figure 35 shows this cost approximation.

Figure 35. Absorption Chiller Capital Costs



E.4. Market Penetration Analysis

EEA has developed a CHP market penetration model that estimates cumulative CHP market penetration in 5-yrar increments. For this analysis, the forecast periods are 2012, 2017, and 2022. These results are interpolated to the output years 2010, 2015, 2020, and 2025. The target market is comprised of the facilities that make up the technical market potential as defined in previously in this section. Thee economic competition module in the market penetration model compares CHP technologies to purchased fuel and power in 5 different sizes and 4 different CHP application types. The calculated payback determines the potential pool of customers that would consider accepting the CHP investment as economic. Additional, non economic screening factors are applied that limit the pool of customers that can accept CHP in any given market/size. Based on this calculated economic potential, a market diffusion model is used to determine the cumulative market penetration for each 5-year time period. The cumulative market penetration, economic potential and technical potential are defined as follows:

- *Technical potential* represents the total capacity potential from existing and new facilities that are likely to have the appropriate physical electric and thermal load characteristics that would support a CHP system with high levels of thermal utilization during business operating hours.
- *Economic potential*, as shown in the table, reflects the share of the technical potential capacity (and associated number of customers) that would consider the CHP investment economically acceptable according to a procedure that is described in more detail below.
- *Cumulative market penetration* represents an estimate of CHP capacity that will actually enter the market between 2008 and 2025. This value discounts the economic potential to reflect non-economic screening factors and the rate that CHP is likely to actually enter the market.

In addition to segmenting the market by size, as shown in the table, the analysis is conducted in four separate CHP market applications (high load and low load factor traditional CHP and high and low load factor CHP with cooling.) These markets are considered individually because both the annual load factor and the installation and operation of thermally activated cooling has an impact on the system economics.

Economic potential is determined by an evaluation of the competitiveness of CHP versus purchased fuel and electricity. The projected future fuel and electricity prices and the cost and performance of CHP technologies determine the economic competitiveness of CHP in each market. CHP technology and performance assumptions appropriate to each size category and region were selected to represent the competition in that size range (Table 52). Additional assumptions were made for the competitive analysis. Technologies below 1 MW in electrical capacity are assumed to have an economic life of 10 years. Larger systems are assumed to have an economic life of 15 years. Capital related amortization costs were based on a 10% discount rate. Based on their operating characteristics (each category and each size bin within the category have specific assumptions about the annual hours of CHP operation (80-90% for the high load factor cases with appropriate adjustments for low load factor facilities), the share of recoverable thermal energy that gets utilized (80%-90%), and the share of useful thermal energy that is used for cooling compared to traditional heating. The economic figure-of-merit chosen to reflect this competition in the market penetration model is simple payback.[73] While not the most sophisticated measure of a project's performance, it is nevertheless widely understood by all classes of customers.

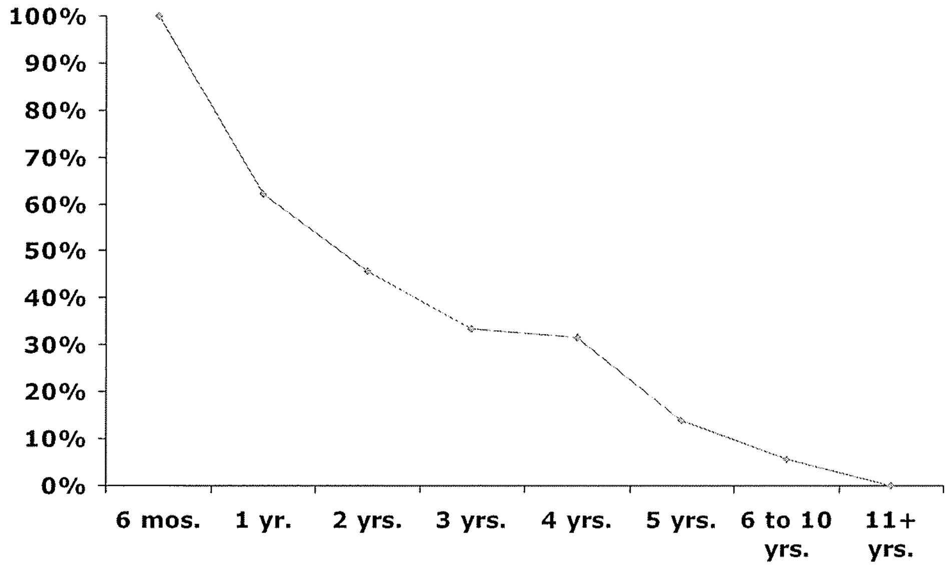
Table 52. Technology Competition Assumed within Each Size Category

Market Size Bins	*Competing Technologies*
50 - 500 kW	100 kW Recip Engine
	70 kW Microturbine
	150 kW PEM Fuel Cell
500 - 1,000 kW	300 kW Recip Engine (multiple units)
	70 kW Microturbine (multiple units)
	250 kW MC/SO Fuel Cell (multiple units)
1 - 5 MW	3 MW Recip Engine
	3 MW Gas Turbine
	2 MW MC Fuel Cell
5 - 20 MW	5 MW Recip Engine
	5 MW Gas Turbine
20 - 100 MW	40 MW Gas Turbine

Rather than use a single payback value, such as 3-years or 5-years as the determinant of economic potential, we have based the market acceptance rate on a survey of commercial and industrial facility operators concerning the payback required for them to consider installing CHP. Figure 36 shows the percentage of survey respondents that would accept CHP investments at different payback levels (CEC 2005b). As can be seen from the figure, more than 30% of customers would reject a project that promised to return their initial investment in just one year. A little more than half would reject a project with a payback of 2 years. This type of payback translates into a project with an ROI of between 49-100%. Potential explanations for rejecting a project with such high returns is that the average customer does not believe that the results are real and is protecting himself from this perceived risk by requiring very high projected returns before a project would be accepted, or that the facility is very capital limited and is rationing its capital raising capability for higher priority projects (market expansion, product improvement, etc.).

[73] Simple payback is the number of years that it takes for the annual operating savings to repay the initial capital investment.

Figure 36. Customer Payback Acceptance Curve



Source: *Primen's 2003 Distributed Energy Market Survey*

For each market segment, the economic potential represents the technical potential multiplied by the share of customers that would accept the payback calculated in the economic competition module.

The estimation of market penetration includes both a non-economic screening factor and a factor that estimates the rate of market penetration (diffusion). The non-economic screening factor was applied to reflect the share of each market size category (i.e., applications of 50 to 500 kW, applications of 500 to 1,000 kW, etc) within the economic potential that would be willing and able to consider CHP at all. These factors range from 32% in the smallest size bin (50-500 kW) to 64% in the largest size bin (more than 20 MW). These factors are intended to take the place of a much more detailed screening that would eliminate customers that do not actually have appropriate electric and thermal loads in spite of being within the target markets, do not use gas or have access to gas, do not have the space to install a system, do not have the capital or credit worthiness to consider investment, or are otherwise unaware, indifferent, or hostile to the idea of adding CHP. The specific value for each size bin was established based on an evaluation of EIA facility survey data and gas use statistics from the iMarket database.

The rate of market penetration is based on a *Bass diffusion curve* with allowance for growth in the maximum market. This function determines cumulative market penetration for each 5-year period. Smaller size systems are assumed to take a longer time to reach maximum market penetration than larger systems. Cumulative market penetration using a Bass diffusion curve takes a typical S-shaped curve. In the generalized form used in this analysis, growth in the number of ultimate adopters is allowed. The curves shape is determined by an initial market penetration estimate, growth rate of the technical market potential, and two factors described as *internal market influence* and *external market influence*.

The cumulative market penetration factors reflect the economic potential multiplied by the non-economic screening factor (maximum market potential) and by the Bass model market cumulative market penetration estimate.

Once the market penetration is determined, the competing technology shares within a size/utility bin are based on a *logit function* calculated on the comparison of the system paybacks. The greatest market share goes to the lowest cost technology, but more expensive technologies receive some market share depending on how close they are to the technology with the lowest payback. (This technology allocation feature is part of the EEA CHP model that is not specifically used for this analysis.)

Two cases were run to show the effects of providing an economic stimulus for CHP market penetration consisting of a capital cost reduction of $500/kW for all CHP systems 5 MW and below. The results of the base case, without incentives, are shown in Table 53. Table 54 shows the results of the $500/kW incentive case.

Table 53. Market Penetration Results for Base Case

CHP Measurement	2010	2015	2020	2025
Cumulative Market Penetration (MW)				
Industrial	0	294	678	937
Commercial/Institutional	0	57	170	263
Total	0	351	848	1,200
Avoided Cooling	0	4	11	15
Scenario Grand Total	0	355	859	1,215
Annual Electric Energy (Million kWh)				
Industrial	0	2023	5014	7,055
Commercial/Institutional	269	543	1085	1,728
Total	269	2565	6099	8,783
Avoided Cooling	0	9	30	49
Scenario Grand Total	269	2,574	6,128	8,832
Incremental Onsite Fuel (billion Btu/year)				
Industrial	0	11,782	27,025	37,161
Commercial/Institutional	0	2,153	6,316	9,742
Total	0	13,935	33,341	46,903
Cumulative Investment (million 2006$)	$0	$380	$942	$1,351
Cumulative Incentive Payments (Million 2006$)	$0	$1	$7	$14

Note: Incentive Payments in the Base Case represent fuel cell tax credits

Table 54. Market Penetration Results for $500/kW Incentive Case

CHP Measurement	2010	2015	2020	2025
Cumulative Market Penetration (MW)				
Industrial	4	379	876	1,209
Commercial/Institutional	3	140	370	546
Total	7	520	1246	1,755
Avoided Cooling	1	16	36	44
Scenario Grand Total	9	536	1,282	1,799
Annual Electric Energy (Million kWh)				
Industrial	41	2548	6140	8,564
Commercial/Institutional	309	1055	2254	3,360
Total	351	3603	8394	11,924
Avoided Cooling	6	44	100	145
Scenario Grand Total	356	3,647	8,494	12,069
Incremental Onsite Fuel (billion Btu/year)				
Industrial	117	14,690	33,771	46,446
Commercial/Institutional	86	4,985	13,161	19,375
Total	203	19,674	46,933	65,820
Cumulative Investment (million 2006$)	$5	$446	$1,045	$1,452
Cumulative Incentive Payments (Million 2006$)	$7	$183	$477	$705

APPENDIX F – THE DEEPER MODEL AND MACRO MODEL

The Dynamic Energy Efficiency Policy Evaluation Routine—or the DEEPER Model—is a 15-sector quasi-dynamic input-output impact model of the U.S. economy.[74] Although an updated model with a new name, the model has a 15-year history of use and development. See, for example, Laitner, Bernow, and DeCicco (1998) and Laitner (2007) for a review of past modeling efforts. The model is generally used to evaluate the macroeconomic impacts of a variety of energy efficiency (including renewable energy) and climate policies at both the state and national level. The national model now evaluates policies for the period 2008 through 2050. Although, the DEEPER Model for the Ohio specific analysis will cover the period between 2008 through 2025. As it is now designed, the model solves for the set of energy prices that achieves a desired and exogenously determined level of greenhouse gas emissions (below some previously defined reference case). Although the model does include non-CO_2 emissions and other emissions reduction opportunities, it currently focuses on energy-related CO_2 emissions and on the prices, policies, and programs necessary to achieve the desired emissions reductions. DEEPER is an Excel-based analytical tool that consists generally of six sets of key modules or groups of worksheets. These six sets of modules now include:

Global data: The information in this module consists of the economic time series data and key model coefficients and parameters necessary to generate the final model results. The time series data includes the projected reference case energy quantities such as trillion Btus and kilowatt-hours, as well as the key energy prices associated with their use. It also includes the projected gross domestic product, wages and salary earnings, and levels of employment as well as information on key technology cost and performance characteristics. The sources of economic information include data from the Energy Information Administration, the Bureau of Economic Analysis, the Bureau of Labor Statistics, and Economy.com. The cost and performance characterization of key technologies is derived from available studies completed by ACEEE and others, as well as data from the Energy Information Administration's (EIA) National Energy Modeling System (NEMS). One of the more critical assumptions in this study is that alternative patterns of electricity consumption will change and/or defer the mix of investments in conventional power plants. Although we can independently generate these impacts within DEEPER, we can also substitute assumptions from the ICF Integrated Planning Model (IPM) and similar models as they may have different characterizations of avoided costs or alternative patterns of power plant investment and spending.

Macroeconomic model: This set of modules contains the "production recipe" for the region's economy for a given "base year"—in this case, 2006, which is the latest year for which a complete set of economic accounts are available for the regional economy. The I-O data, currently purchased from the Minnesota IMPLAN Group (IMPLAN 2007), is essentially a set of input-output accounts that specify how different sectors of the economy buy (purchase inputs) from and sell (deliver outputs) to each other. In this case, the model is now designed to evaluate impacts for 15 different sectors, including: Agriculture, Oil and Gas Extraction, Coal Mining, Other Mining, Electric Utilities, Natural Gas Distribution, Construction, Manufacturing, Wholesale Trade, Transportation and Other Public Utilities (including water and sewage), Retail Trade, Services, Finance, Government, and Households.

Investment, Expenditures and Energy Savings: Based on the scenarios mapped into the model, this worksheet translates the energy policies into a dynamic array of physical energy impacts, investment flows, and energy expenditures over the desired period of analysis. It estimates the needed investment path for an alternative mix of energy efficiency and other technologies (including efficiency gains on both the end-use and the supply side). It also provides an estimate of the avoided investments needed by the electric generation sector. These quantities and expenditures feed

[74] There is nothing particularly special about this number of sectors. The problem is to provide sufficient detail to show key negative and positive impacts while maintaining a manageable sized model. If we choose to reflect a different mix of sectors and stay within the 15 x 15 matrix, that can be done easily. If we wish to expand the number of sectors, that would take some minor programming changes or adjustments to reflect the larger matrix.

directly into the final demand module of the model which then provides the accounting that is needed to generate the set of annual changes in final demand (see the related module description below).

Price dynamics: There are two critical drivers that impact energy prices within DEEPER. The first is a set of carbon charges that are added to retail prices of energy depending on the level of desired level of emission reductions and also depending on the available set of alternatives to achieve those reductions. The second is the price of energy as it might be affected by changed consumption patterns. In this case DEEPER employs an independent algorithm to generate energy price impacts as they reflect changed demand. Hence, the reduced demand for natural gas in the end-use sectors, for example, might offset increased demand by utility generators. If the net change is a decrease in total natural gas consumption, the wellhead prices might be lowered. Depending on the magnitude of the carbon charge, the change in retail prices might either be higher or lower than the set of reference case prices. This, in turn, will impact the demand for energy as it is reflected in the appropriate modules. In effect, then, DEEPER scenarios rely on both a change in prices and quantities to reflect changes in overall investments and expenditures.

Final demand: Once the changes in spending and investments have been established and adjusted to reflect changes in prices within the other modules of DEEPER, the net spending changes in each year of the model are converted into sector-specific changes in final demand. This, in turn, drives the input-output model according to the following predictive model:

$$X = (I-A)^{-1} * Y$$

where:

X = total industry output by sector
- I = an identity matrix consisting of a series of 0's and 1's in a row and column format for each sector (with the 1's organized along the diagonal of the matrix)
- A = the production or accounting matrix also consisting of a set of production coefficients for each row and column within the matrix

Y = final demand, which is a column of net changes in final demand by sector

This set of relationships can also be interpreted as

$$\Delta X = (I-A)^{-1} * \Delta Y$$

which reads: a change in total sector output equals $(I-A)^{-1}$ times a change in final demand for each sector. Employment quantities are adjusted annually according to exogenous assumptions about labor productivity in each of the sectors (based on Bureau of Labor Statistics forecasts).

Results: For each year of the analytical time horizon (again out to 2025 for the Ohio specific analysis), the model copies each set of results into this module in a way that can also be exported to a separate report.

Further results from Ohio's DEEPER analysis is provided to show macroeconomic trends between 5-year time periods. Although similar 2015 & 2025 results were presented in the body of this report, differences between 5-year time periods offer more reference points for the reader to understand Ohio's macroeconomic trends under the efficiency scenario. This section highlights the net changes Ohio's economy will experience as the result of our efficiency scenario.

Table 55. Changes in Ohio Electricity Production and Financial Impacts from Energy Efficiency Policy Scenario: 2010, 2015, 2020 & 2025

(Millions of 2006 $)	2010	2015	2020	2025
Efficiency Gains (GWh)	1,383	9,728	22,845	40,069
Change from Reference Case	2.3%	15.5%	36.3%	62.9%
Policy Cost	$89	$154	$413	$489
Investment	$214	$629	$1,152	$1,382
Annual Consumer Outlays	$193	$723	$1,496	$2,146
Annual Electricity Savings	$111	$1,154	$2,961	$5,461
Electricity Supply Cost Adjustment	$58	$267	$626	$1,059
Net Consumer Savings	-$23	$431	$1,465	$3,314
Net Cumulative Energy Savings	$9	$954	$5,951	$18,980

The macroeconomic module of the DEEPER model traces how each set of changes works or ripples its way through the Ohio economy in each year of the assessment period, see Table 55. This module estimates the number of jobs and amount of wages each sector provides the Ohio economy. Changes in sectoral spending are provided in Table 56 below.

Table 56. Changes in Sector Spending (Millions of 2006 Dollars)

Sector	2010	2015	2020	2025
Agriculture	$0.5	$7.8	$29.1	$47.1
Oil and Gas Extraction	$0.3	$5.0	$21.5	$32.3
Coal Mining	$0.0	$0.1	$0.6	$0.9
Other Mining	$0.2	$3.2	$13.9	$20.8
Construction	$121.0	$195.9	$479.1	$719.0
Manufacturing	$8.4	$115.1	$362.1	$648.0
Petroleum Refining	$2.8	$40.8	$163.1	$255.0
Electric Utility Services	-$44.5	-$167.0	-$388.6	-$656.8
Natural Gas Utility Services	-$52.6	-$397.2	- $1,040.5	-$1,690.5
Transportation Other Public Utilities	-$3.0	$3.0	$14.0	$35.0
Wholesale Trade	$9.9	$150.8	$415.2	$809.2
Services	$40.1	$464.3	$1,278.1	$2,462.2
Financial Services	-$11.7	$48.1	$125.1	$244.4
Governmental Services	$5.0	$13.2	$36.5	$58.5

There are other support spreadsheets as well as routines in visual basic programming that support the automated generation of model results and reporting. For more detail on the model assumptions and economic relationships, please refer to the forthcoming model documentation (Laitner 2009). For a review of how an I-O framework might be integrated into other kinds of modeling activities, see Hanson and Laitner (2007). While not an equilibrium model, we borrow from some key concepts of mapping technology representation into DEEPER using the general scheme outlined in Laitner and Hanson (2007).