Missouri Statewide DSM Market Potential Study

Draft Report

Prepared for

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1. Executive Summary

This study assessed the electric and natural gas DSM (demand side management) potential for the residential, commercial, and industrial sectors in the state of Missouri. The study was commissioned by the Missouri Public Service Commission (PSC), supported by the Missouri Department of Natural Resources. The goal of this study was to determine the levels of DSM savings available in the state of Missouri, the costs associated with procuring these savings, and whether the measures delivering the savings are cost effective. This study provides energy-efficiency and demand-response potential estimates for the period from 2011-2030.

1.1 Scope and Approach

In this study, three types of energy-efficiency potential were estimated:

- **Technical potential,** defined as the *complete* penetration of all measures analyzed in applications where they were deemed *technically* feasible from an *engineering* perspective
- **Economic potential,** defined as the *technical potential* of those energy-efficiency measures that are cost-effective when compared to supply-side alternatives
- **Achievable program potential,** the amount of savings that would occur in response to specific program funding and measure incentive levels.

In addition, naturally occurring energy-efficiency impacts were estimated. These are savings that result from normal market forces. Achievable program potential reflects savings that are projected beyond those that would occur naturally in the absence of any market intervention.

The method used for estimating potential is a “bottom-up” approach in which energy-efficiency costs and savings are assessed at the customer-segment and energy-efficiency measure level. For cost-effective measures (based on the total resource cost, or TRC, test), program savings potential was estimated as a function of measure economics, rebate levels, and program marketing and education efforts. The modeling approach was implemented using KEMA’s DSM ASSYST™ model. This model allows for efficient integration of large quantities of measure, building, and economic data to determine energy-efficiency potential.

For this study, three different program scenarios were constructed. Two scenarios were developed at the specific direction of the PSC based on measure payback levels. These are characterized as follows:

- **One-year Payback -** In this scenario we assume customer incentives are provided such that all cost-effective measures have a payback period of one year. For measures that have payback periods of one year or less without incentives, no incentives are provided, but they may be supported through marketing, educational, and other program efforts.

- **Three-year Payback** - In this scenario we assume customer incentives are provided such that all cost-effective measures have a payback period of three years. For measures that have payback periods of three years or less without incentives, no incentives are provided, but they may be supported through marketing, educational, and other program efforts.

After reviewing the results, KEMA developed a third scenario, characterized in the following manner:

- **KEMA Norm -** In this scenario, we remove the constraints imposed by the PSC direction on payback and perform analysis in our customary fashion, with a measure incentive set at 75% of incremental cost.

In most of our analyses the scenarios we develop are based on the degree of programmatic financial support for measure installation. This support is financial incentive expressed as a percentage of incremental cost difference between the base measure and the efficient measure. In many analyses clients direct scenarios with incentives set at 50%, 75%, and 100% of incremental cost. These incentive levels correlate to average, aggressive, and theoretical maximum levels of program effort.

Results in 50-percent incentive scenarios are in most cases consistent with typical past program experience. In light of the requirements of *The Missouri Energy Efficiency Investment Act of 2009* (references as “SB 376”) and the proposed draft rule 4 CSR 240-20.094 focus on “realistic achievable energy savings,” we determined to estimate potential based on an incentive of 75% of incremental cost. This reflects a strong commitment to achieving all cost-effective savings potential while remaining within the realm of realistic.

In light of the law, it could be argued that the 100-percent incentive scenario would have been appropriate. However, we have no “real world” program-wide experience where all the incremental measure costs are paid for over an extended period of time. In some cases, the equivalent of 100-percent incentives have been offered for limited measures and customer segments in order to overcome high barriers in specific markets and to gain a high level of program participation. We chose to present for the PSC’s information a scenario that while aggressive, is within realistic bounds.

The assessment addressed measures and processes that are commercially available with proven savings and customer acceptance. We excluded a general modeling of emerging technologies and behavioral-conservation approaches. These additional components show promise for future DSM program impacts, but projections of their savings potentials have much more uncertainty than those of more standard measures. Nor did the study address incremental improvements in energy efficiency due to the ongoing evolution and improvement of technologies. These improvements will lead to increased energy-efficiency potential, over time. Also, the study did not address the ongoing tightening of equipment and building standards, which will in turn lead to a decrease in energy-efficiency potential, over time.

To estimate demand response (DR) impacts, we reviewed impacts from the Federal Energy Regulatory Commission's (FERC) *2009 National Assessment of Demand Response Potential*[1] (NADR) for the State of Missouri and customized the results to the state of Missouri, utilizing information developed by the KEMA team from Missouri-specific sources.

1.2 Results

We report overall results of the DSM potential study in this section. Cumulative results for the period from 2010 to 2020 are shown. Our analysis covered a twenty-year period, and the results of this analysis will be included in Appendix H, to be delivered pending feedback from the scheduled review session on January 20, 2011. In our experience the further into the future projections go, on any topic, the greater the uncertainty. For the purposes of policy, actions that will be taken in the near term, and comparison to other studies and past results, we find that the ten-year timeframe is most useful, and credible.

Our analysis is conservative, in that we did not include savings from technologies or program efforts that are not currently in existence. Neither did we include predictions on savings from behavioral or societal shifts, e.g. an aggressive carbon emission reduction program on the national level. The measures included in our analysis are those where we have very high confidence in the savings estimates, based on documented results from existing programs, reliable evaluation, or other credible sources.

[1] *A National Assessment of Demand Response Potential*, Staff Report, Federal Energy Regulatory Commission, prepared by The Brattle Group, Freeman, Sullivan & Co., and Global Energy Partners, LLC, June 2009.

1.2.1 Electric Potential Overview

Table 1-1and Table 1-2 summarize the study results for the electric sector.

Table 1-1
Electric Energy Savings Potential Overview

Sector	2020 Base Energy Use (GWH)	Ten Year Cumulative Potential - GWh				
		Technical Potential	Economic Potential	Three Year Payback Achievable Potential - Gross	One Year Payback Achievable Potential - Gross	75% Incentive Achievable Potential - Gross
Residential Existing	41,430	17,579	11,667			
Residential New	104	372	372			
Subtotal	41,534	17,950	12,039	3,191	4,509	6,701
Savings % of Base		**43%**	**29%**	**8%**	**11%**	**16%**
Commercial Existing	32,193	10,274	7,228			
Commercial New	243	1,283	1,283			
Subtotal	32,436	11,558	8,511	2,309	3,163	3,495
Savings % of Base		**36%**	**26%**	**7%**	**10%**	**11%**
Industrial	18,586	3,174	2,658	1,101	1,722	1,745
Savings % of Base		**17%**	**14%**	**6%**	**9%**	**9%**
Total	92,556	32,682	23,208	6,601	9,394	11,942
Savings % of Base		**35%**	**25%**	**7%**	**10%**	**13%**

Table 1-2
Electric Demand Savings Potential Overview

Sector	2020 Base Demand (MW)	Ten Year Cumulative Potential - MW				
		Technical Potential	Economic Potential	Three Year Payback Achievable Potential - Gross	One Year Payback Achievable Potential - Gross	75% Incentive Achievable Potential - Gross
Residential Existing	9,265	3,960	3,102			
Residential New	23	62	62			
Subtotal	9,288	4,022	3,164	832	1,623	1,617
Savings % of Base		**43%**	**34%**	**9%**	**17%**	**17%**
Commercial Existing	5,496	1,674	971			
Commercial New	42	180	180			
Subtotal	5,538	1,853	1,151	318	452	483
Savings % of Base		**33%**	**21%**	**6%**	**8%**	**9%**
Industrial	2,313	350	281	108	170	170
Savings % of Base		**15%**	**12%**	**5%**	**7%**	**7%**
Total	17,139	6,225	4,596	1,258	2,245	2,269
Savings % of Base		**36%**	**27%**	**7%**	**13%**	**13%**

Demand savings from demand response programs presented separately and are not incorporated in the tables above.

1.2.2 Gas Potential Overview

KEMA analyzed the potential energy savings for natural gas using the same scenarios as electricity. Table 1-3 summarizes the results of this analysis.

Table 1-3
Natural Gas Energy Savings Potential Overview

Sector	2020 Base Energy Use - Dekatherms	Ten Year Cumulative Potential - Dekatherms				
		Technical Potential	Economic Potential	Three Year Payback Achievable Potential - Gross	One Year Payback Achievable Potential - Gross	75% Incentive Achievable Potential - Gross
Residential Existing	116,802,808	51,132,703	23,365,190			
Residential New	292,739	3,333,059	3,333,059			
Subtotal	117,095,547	54,465,762	26,698,248	7,877,888	11,790,623	15,789,881
Savings % of Base		**47%**	**23%**	**7%**	**10%**	**13%**
Commercial Existing	69,090,102	24,861,821	17,725,504			
Commercial New	522,091	2,754,860	220,734			
Subtotal	69,612,193	27,616,681	17,946,238	1,999,415	4,653,440	6,232,421
Savings % of Base		**40%**	**26%**	**3%**	**7%**	**9%**
Industrial	67,097,602	9,032,250	8,535,630	1,199,216	2,036,964	3,726,369
Savings % of Base		**13%**	**13%**	**2%**	**3%**	**6%**
Total	253,805,342	91,114,692	53,180,116	11,076,520	18,481,027	25,748,671
Savings % of Base		**36%**	**21%**	**4%**	**7%**	**10%**

1.2.3 Demand Response Potential Overview

The demand response potential was developed using the NADR model as noted above. NADR develops potential under four scenarios, described below.

- Business-as-usual (BAU): BAU assumes current programs and tariffs are held constant;
- Expanded BAU (EBAU):EBAU assumes participation rates are increased to equal the 75th percentile of ranked participation rates of similar programs.
- Achievable Participation (AP): AP assumes advanced metering infrastructure (AMI) is universally deployed, and dynamic pricing is the opt-out default tariff.
- Full Participation (FP): EP assumes that dynamic pricing and the acceptance of enabling technology is mandatory. This scenario quantifies the maximum cost-effective DR potential, absent any regulatory and market barriers.

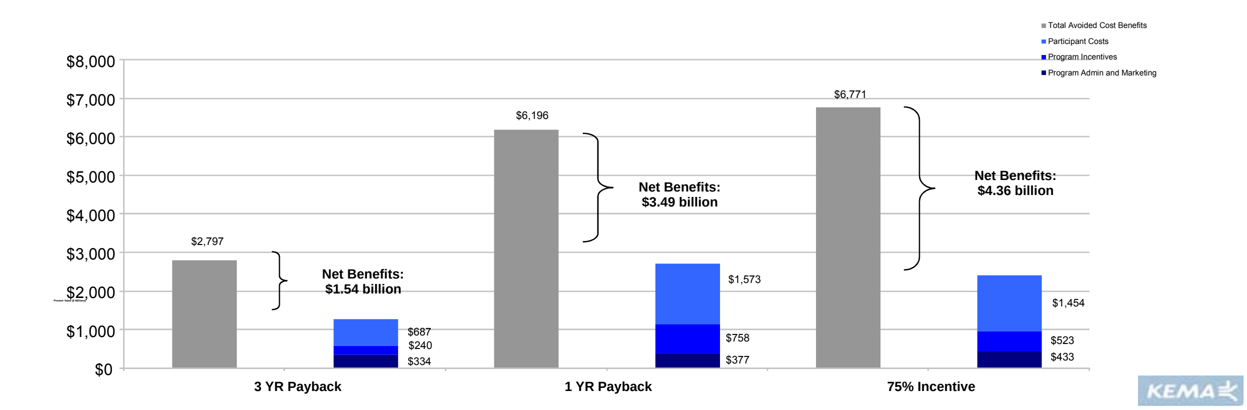
Table 1-4 summarizes the results of the NADR model across all four scenarios.

Table 1-4
NADR Demand Response Potential Summary

Program mechanism	2010 MW	2015 MW	2020 MW	2025 MW	2030 MW
BAU					
Pricing With Enabling Technology	0	0	0	0	0
Pricing Without Enabling Technology	0	0	0	0	0
Automated or Direct Control DR	63	63	63	63	63
Interruptible Tariffs	219	219	219	219	219
Other DR	0	0	0	0	0
TOTAL	**282**	**282**	**282**	**282**	**282**
Expanded BAU					
Pricing With Enabling Technology	0	0	0	0	0
Pricing Without Enabling Technology	0	31	46	62	85
Automated or Direct Control DR	336	839	850	864	875
Interruptible Tariffs	326	647	677	713	752
Other DR	26	316	328	343	358
TOTAL	**688**	**1833**	**1900**	**1982**	**2070**
Achievable Participation					
Pricing With Enabling Technology	0	660	1255	1294	1335
Pricing Without Enabling Technology	0	353	674	697	722
Automated or Direct Control DR	336	521	241	247	252
Interruptible Tariffs	326	647	677	713	752
Other DR	26	218	134	142	149
TOTAL	**688**	**2399**	**2982**	**3093**	**3210**
Full Participation Potential					
Pricing With Enabling Technology	0	1599	3045	3142	3243
Pricing Without Enabling Technology	0	139	268	281	296
Automated or Direct Control DR	336	409	63	63	63
Interruptible Tariffs	326	647	677	713	752
Other DR	26	149	0	0	0
TOTAL	**688**	**2942**	**4052**	**4200**	**4353**

Figure 1-1 depicts costs and benefits under each program funding scenario from 2010 to 2020 for electric energy efficiency.

Figure 1-1
Benefits and Costs of Electric Efficiency Savings—2010-2020*

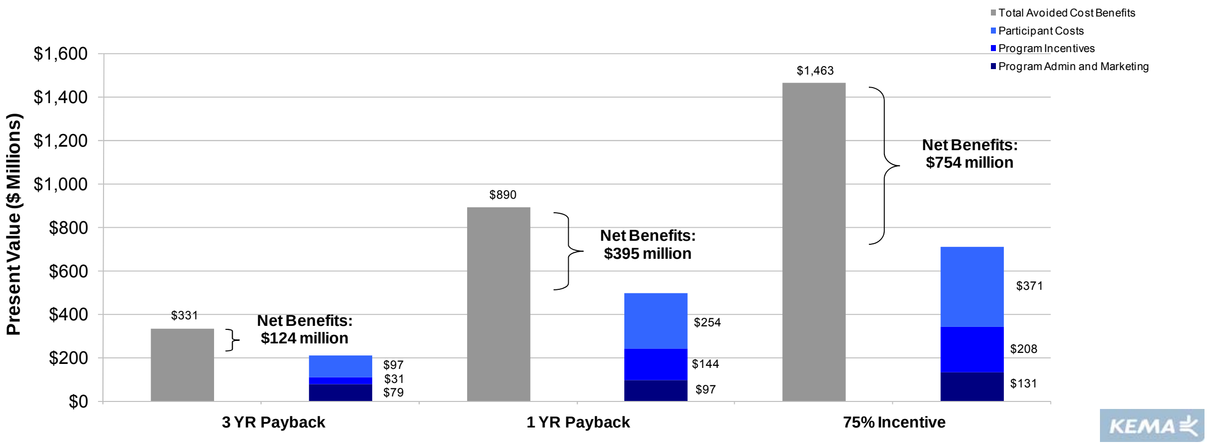


* Present value of benefits and costs over normalized 20-year measure lives; nominal discount rate is 7.9 percent, inflation rate is 1.5 percent.

Figure 1-2 shows the same sets of results for natural gas. For both electricity and natural gas, all three of the program funding scenarios are cost-effective based on the TRC (total resource cost) test, which was the test used in this study to determine program cost-effectiveness.

Figure 1-2

Benefits and Costs of Natural-Gas Efficiency Savings—2010-2020* -



* Present value of benefits and costs over normalized 20-year measure lives; nominal discount rate is 7.7 percent, inflation rate is 1.5 percent.

The tables below provide a snapshot summary of the estimated programmatic savings, costs, and benefits for each scenario.

Table 1-5 Summary of Achievable Electric Potential Results – 2010 - 2020

Result - Programs	3 YR Payback	1 YR Payback	75% Incentive
Gross Energy Savings - GWh	6,406	9,696	10,185
Gross Peak Demand Savings - MW	1,175	2,259	2,169
Net Energy Savings - GWh	3,281	6,571	7,561
Net Peak Demand Savings - MW	779	1,863	1,801
Program Costs - Real, $ Million			
Administration	$193	$246	$317
Marketing	$223	$223	$221
Incentives	$597	$2,148	$1,723
Total	$1,013	$2,617	$2,260
PV Avoided Costs	$2,797	$6,196	$6,771
PV Annual Program Costs (Adm/Mkt)	$334	$377	$433
PV Net Measure Costs	$927	$2,331	$1,977
Net Benefits	$1,536	$3,488	$4,361
TRC Ratio	2.22	2.29	2.81

Table 1-6
Summary of Achievable Natural Gas Potential Results—2010-2020

Result - Programs	3 YR Payback	1 YR Payback	75% Incentive
Gross Energy Savings - Therms (Million	110.8	184.8	257.5
Net Energy Savings - Therms (Millions)	45.8	119.9	192.6
Program Costs - Real, $ Million			
Administration	$64	$87	$128
Marketing	$34	$34	$34
Incentives	$27	$320	$534
Total	$124	$440	$695
PV Avoided Costs	$331	$890	$1,463
PV Annual Program Costs (Adm/Mkt)	$79	$97	$131
PV Net Measure Costs	$129	$398	$578
Net Benefits	$124	$395	$754
TRC Ratio	1.60	1.80	2.06

The scenarios analyzed show benefit cost ratios increasing for both energy sources as the investment increase.

1.2.4 Uncertainty of Results

We want to caution the reader that there is inherent uncertainty in the results presented in this report because they are forecasts of what could happen in the future. Our estimates of technical and economic potential have the lowest degree of uncertainty. These are estimates that account for savings, costs, and current saturations of DSM measures but do not factor in human behavior.

The achievable program estimates do take into account behavior, as our modeling efforts try to predict program participation levels while factoring in measure awareness and economics, as well as barriers to measure uptake. Hence, the uncertainty in our achievable potential estimates is greater.

1.3 Conclusions

As the results of this study indicate, there is a significant amount of energy efficiency potential remaining in the state of Missouri. For electricity, the residential and commercial sectors provide the largest sources of potential savings.

Key residential end uses, in terms of potentials, include cooling, lighting, and refrigeration. Whole-building new construction measures are also a source of large potential savings. It may be necessary to offer fairly large incentives to capture the largest amounts of residential electricity savings potential, as our modeling results show the largest jump in savings coming when incentives are increased to 75 percent of incremental measure cost. Plug loads, home entertainment equipment, and home office equipment also provide a significant of energy savings potential, but use of customer incentives for measures in these end uses does not appear to be the way to go as there is usually very little cost differential between standard-efficiency and high-efficiency equipment. Customer education and upstream activities are probably more useful approaches to increase the availability and purchases of more efficient electronic equipment.

In the commercial sector, lighting and cooling continue to provide the largest sources of electric energy efficiency potential. Data center and server measures also appear to be a growing source of potential energy savings.

Demand response programs will continue to be a large source of peak demand savings.

The residential sector is by far the largest source of natural-gas savings potential. The key residential end uses are space heating and water heating, and key measures include high efficiency water heaters, furnaces and boilers as well as building shell measures such as insulation and weatherization. Residential new construction measures also provide a large source of potential natural-gas savings. Similar to the electric findings, it may take fairly large incentives to capture high levels of residential gas potential.

Emerging technologies will play an increasing role in the energy efficiency portfolio as traditional measures reach high market saturation levels. It will be useful for Missouri to run pilot programs to test both the technical effectiveness and the market acceptance of emerging technologies before rolling out full scale programs.

2. Introduction

2.1 Overview

The study will:

1. Help determine how much electric and natural-gas technical, economic, achievable (market), and naturally occurring potential exists within the State of Missouri
2. Assist in establishing mechanisms by which the State can continuously evaluate opportunities for cost-effective DSM, including but not limited to financial modeling.

KEMA, Inc. (KEMA) was retained to conduct this demand-side management (DSM) market potential study. The study provides estimates of potential electricity and peak-demand savings and natural-gas savings from DSM measures in Missouri.

The scope of this study includes new and existing residential and nonresidential buildings, as well as industrial process savings. The study covers an 11-year period spanning 2010-2020. Given the near- to mid-term focus, the base study was restricted to DSM measures that are presently commercially available. A number of measures were evaluated as emerging technologies, for example LED lighting. While commercially available, these products are characterized by limited availability, low consumer awareness, uncertainty about average energy savings, and high current costs that have the potential to drop significantly with market adoption. Unit energy savings and cost inputs for these measures are near-term (2-3 year) forecasts, based on current trends.

Data for the study come from a number of different secondary sources that include internal Missouri utility studies and data, as well as a variety of information from third parties and significant, if not uniformly successful, efforts to collect data from Missouri stakeholders.

2.2 Study Approach

This study involved identification and development of baseline end-use and measure data and development of estimates of future energy-efficiency impacts under varying levels of program effort. Information from secondary sources, to aid in development of the baseline and measure data.

The baseline characterization allowed us to identify the types and approximate sizes of the various market segments that are the most likely sources of DSM potential in Missouri. These characteristics then served as inputs to a modeling process that incorporated Missouri energy-cost parameters and specific energy-efficiency measure characteristics (such as costs, savings, and existing penetration estimates) to provide more detailed potential estimates.

To aid in the analysis, we utilized the KEMA DSM ASSYST™ model. This model provides a thorough, clear, and transparent documentation database, as well as an extremely efficient data processing system for estimating technical, economic, and achievable potential. We estimated technical, economic, and achievable program potential for the residential, commercial, and industrial sectors, with a focus on energy-efficiency impacts over the next 10 years.

To estimate demand response (DR) impacts, we reviewed impacts from the Federal Energy Regulatory Commission's *2009 National Assessment of Demand Response Potential*[2] for the State of Missouri and customized the results to the state of Missouri, utilizing information on Missouri's peak demand relative to the Colorado peak demand and information on current programs being run by Xcel Energy.

2.3 Layout of the Report

Section 3 discusses the methodology and concepts used to develop the technical, economic, and achievable potential estimates. Section 4 provides baseline results developed for the study. Section 6 discusses the results of the electric energy-efficiency potential analysis by sector and over time. Section 6 presents similar results for gas energy-efficiency potential. Section 7 presents demand-response potential results.

The report contains the following appendices:

- Appendix A: Detailed Methodology and Model Description—Further detail on what was discussed in Section 2.
- Appendix B: Measure Descriptions—Describes the measures included in the study.
- Appendix C: Economic Inputs—Provides avoided cost, electric rate, discount rate, and inflation rate assumptions used for the study.
- Appendix D: Building and TOU Factor Inputs—Shows the base household counts, square footage estimates for commercial building types, and base energy use by industrial segment. This appendix also includes time-of-use factors by sector and end-use.

[2] *A National Assessment of Demand Response Potential*, Staff Report, Federal Energy Regulatory Commission, prepared by The Brattle Group, Freeman, Sullivan & Co., and Global Energy Partners, LLC, June 2009

- Appendix E: Measure Inputs—Lists the measures included in the analysis with the costs, estimated savings, applicability, and estimated current saturation factors.
- Appendix F: Technical and Economic Non-Additive Measure Level Results—Shows energy-efficiency potential for each measure independent of any other measure.
- Appendix G: Supply-Curve Data—Shows the data behind the energy supply curves provided in Section 5 of the report.
- Appendix H: Achievable Program Potential—Provides the detailed forecasts for the achievable potential scenarios over the full analysis horizon.

3. Methods and Scenarios

This section provides a brief overview of the concepts, methods, and scenarios used to conduct this study. Additional methodological details are provided in Appendix A.

3.1 Characterizing the Energy-Efficiency Resource

Energy efficiency has been characterized for some time now as an alternative to energy supply options, such as conventional power plants that produce electricity from fossil or nuclear fuels. In the early 1980s, researchers developed and popularized the use of a conservation supply-curve paradigm to characterize the potential costs and benefits of energy conservation and efficiency. Under this framework, technologies or practices that reduced energy use through efficiency were characterized as “liberating ‘supply’ for other energy demands” and could therefore be thought of as a resource and plotted on an energy supply curve. The energy-efficiency resource paradigm argued simply that the more energy efficiency or “nega-watts” produced, the fewer new plants would be needed to meet end-users’ power demands.

3.1.1 Defining Energy-Efficiency Potential

Energy-efficiency potential studies were popular throughout the utility industry from the late 1980s through the mid-1990s. This period coincided with the advent of what was called least-cost or integrated resource planning (IRP). Energy-efficiency potential studies became one of the primary means of characterizing the resource availability and value of energy efficiency within the overall resource planning process.

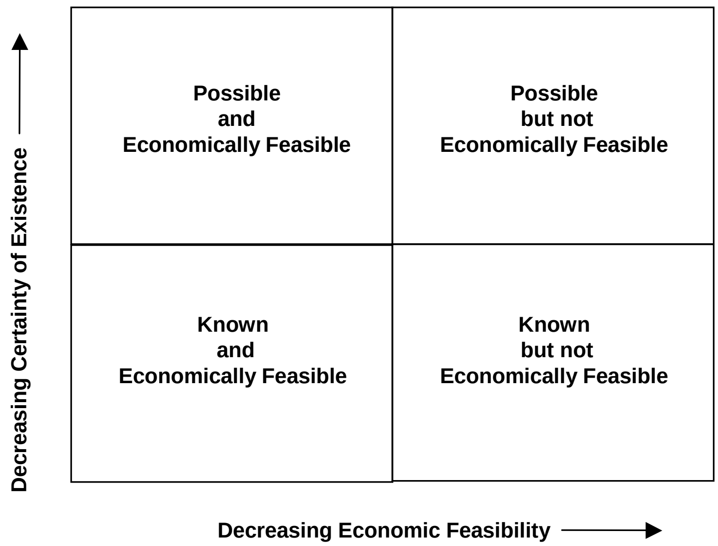
Like any resource, there are a number of ways in which the energy-efficiency resource can be estimated and characterized. Definitions of energy-efficiency potential are similar to definitions of potential developed for finite fossil-fuel resources, like coal, oil, and natural gas. For example, fossil-fuel resources are typically characterized along two primary dimensions: the degree of geological certainty with which resources may be found and the likelihood that extraction of the resource will be economic. This relationship is shown conceptually in Figure 3-1.

Somewhat analogously, this energy-efficiency potential study defines several different *types* of energy-efficiency *potential*, namely, technical, economic, achievable program, and naturally occurring. These potentials are shown conceptually in Figure 3-2 and described below.

- **Technical potential** is defined in this study as the *complete* penetration of all measures analyzed in applications where they were deemed *technically* feasible from an *engineering* perspective.

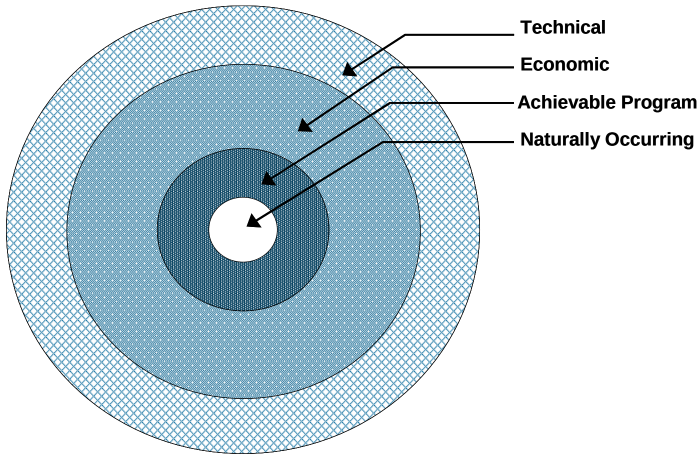
Figure 3-1

Conceptual Framework for Estimates of Fossil Fuel Resources



- **Economic potential** refers to the *technical potential* of those energy conservation measures that are cost effective when compared to supply-side alternatives.
- **Achievable program potential** refers to the amount of savings that would occur in response to specific program funding and measure incentive levels. Savings associated with program potential are savings that are projected beyond those that would occur naturally in the absence of any market intervention.
- **Naturally occurring potential** refers to the amount of savings estimated to occur as a result of normal market forces; that is, in the absence of any utility or governmental intervention.

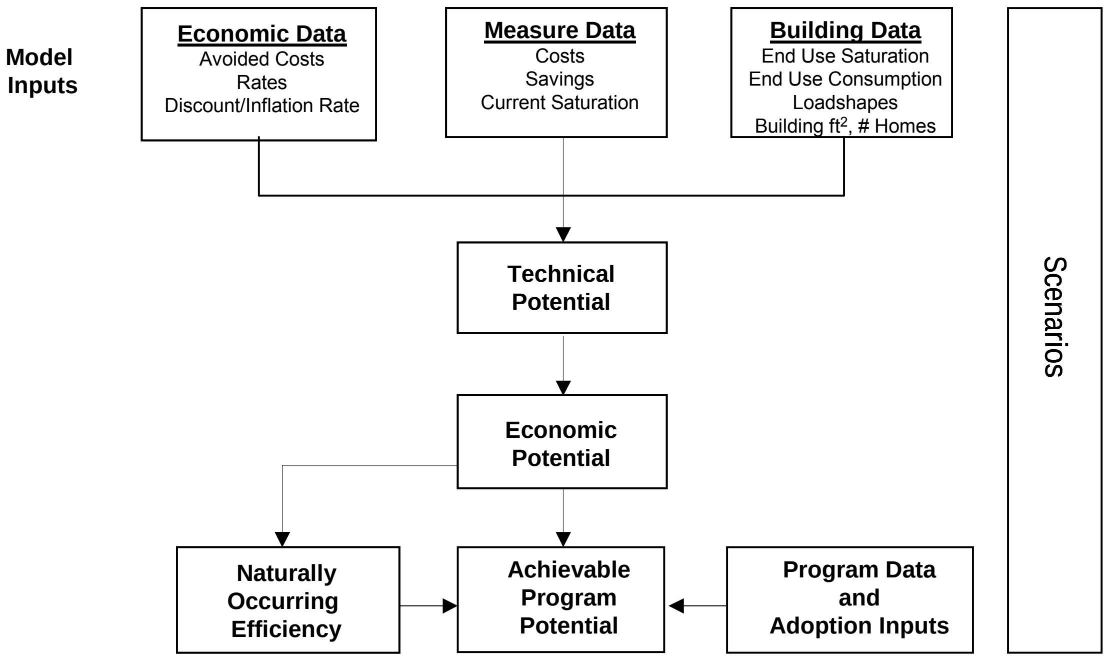
Figure 3-2
Conceptual Relationship among Energy-Efficiency Potential Definitions



3.2 Summary of Analytical Steps Used in this Study

The crux of this study involves carrying out a number of basic analytical steps to produce estimates of the energy-efficiency potentials introduced above. The basic analytical steps for this study are shown in relation to one another in Figure 3-3. The bulk of the analytical process for this study was carried out in a model developed by KEMA for conducting energy-efficiency potential studies. Details on the steps employed and analyses conducted are described in Appendix A. The model used, DSM ASSYST™, is a Microsoft Excel®-based model that integrates technology-specific engineering and customer behavior data with utility market saturation data, load shapes, rate projections, and marginal costs into an easily updated data management system.

Figure 3-3
Conceptual Overview of Study Process



The key steps implemented in this study are:

Step 1: Develop Initial Input Data

- Develop a list of energy-efficiency measure opportunities to include in scope. In this step, an initial draft measure list was developed and circulated by the PSC to stakeholders for comments. The final measure list was developed after consideration of the comments.
- Gather and develop technical data (costs and savings) on efficient measure opportunities. Data on measures were gathered from a variety of sources. Measure descriptions are provided in Appendix B, and detail on measure inputs is provided in Appendix E.
- Gather, analyze, and develop information on building characteristics, including total square footage or total number of households, energy consumption and intensity by end use, end-use consumption load patterns by time of day and year (i.e., load shapes), market shares of key electric consuming equipment, and market shares of energy-efficiency technologies and practices. Section 4 of this report describes the baseline data developed for this study.

- Collect data on economic parameters: avoided costs, electricity rates, discount rates, and inflation rate. These inputs are provided in Appendix C of this report.

Step 2: Estimate Technical Potential and Develop Supply Curves

- Match and integrate data on efficient measures to data on existing building characteristics to produce estimates of technical potential and energy-efficiency supply curves.

Step 3: Estimate Economic Potential

- Match and integrate measure and building data with economic assumptions to produce indicators of costs from different viewpoints (e.g., societal and consumer).
- Estimate total economic potential.

Step 4: Estimate Achievable Program and Naturally Occurring Potentials

- Screen initial measures for inclusion in the program analysis. This screening may take into account factors such as cost effectiveness, potential market size, non-energy benefits, market barriers, and potentially adverse effects associated with a measure. For this study, measures were screened using the total-resource-cost test, while considering only electric or natural gas avoided-cost benefits.
- Gather and develop estimates of program costs (e.g., for administration and marketing) and historic program savings.
- Develop estimates of customer adoption of energy-efficiency measures as a function of the economic attractiveness of the measures, barriers to their adoption, and the effects of program intervention.
- Estimate achievable program and naturally occurring potentials.

Step 5: Scenario Analyses

- Recalculate potentials under alternate program scenarios.

3.3 Scenario Analysis

Scenario analysis is a tool commonly used to structure the uncertainty and examine the robustness of projected outcomes to changes in key underlying assumptions. This section describes the alternative scenarios under which demand-side management (DSM) potential was estimated in this study. We developed two of these scenarios of DSM potential at the direction of the PSC. We developed the third scenario for comparison purposes.

The cost components of program funding that may vary under each scenario include:

Marketing and Education Expenditures

- Customers must be aware of efficiency measures and their associated benefits in order to adopt those measures. In our analysis, program marketing expenditures are converted to increases in awareness. Thus, under higher levels of marketing expenditures, higher levels of awareness are achieved.

Incentives and Direct Implementation Expenditures

- The higher the percentage of measure costs paid by the program, the higher the participants' benefit-cost ratios and, consequently, the number of measure adoptions.

Administration Expenditures

- Purely administrative costs, though necessary and important to the program process, do not directly lead to adoptions; however, they have been included in program funding because they are an input to program benefit-cost tests.

For each analysis, three program-funding scenarios were considered: a three year payback incentive scenario, a one year payback scenario and a typical aggressive scenario. These scenarios are discussed below.

In all scenarios, a number of measures were modeled without financial incentives. These include office equipment power-management enabling, industrial operations and maintenance (O&M) measures, and Energy Star office equipment and consumer electronics for the residential sector. Because these measures are very cost effective, it was deemed that provision of an incentive would primarily benefit free riders.

Note for the low-income segment, all scenarios reflect 100 percent incentives (as a percent of incremental measure cost). Program effort was adjusted across scenarios such that low-income program potentials roughly track other residential program potentials.

3.3.1 One-year Payback Scenario

In the One year payback scenario, base incentive levels are set to a one year payback. Program administration budgets are set at moderately aggressive amounts, roughly corresponding to program support levels. In this case measures that had a less than one year natural (i.e. without intervention) payback were modeled without incentives.

3.3.2 Three-year Payback Scenario

In the three year payback scenario, base incentive levels are set to a Three year payback. Program administration budgets are set at modest amounts, roughly corresponding to minimum program support levels. In this case measure that had a less than three year natural payback modeled without incentives.

3.3.3 KEMA Norm Scenario

In this scenario, incentives were increased to cover 75 percent of incremental measure costs, with the exception of the measures noted above as modeled without incentive. Program budgets were adjusted to reflect the level of administrative and marketing effort necessary to support the level of incentives.

4. Baseline Results

4.1 Overview

Estimating the potential for energy-efficiency improvements requires a comparison of the energy impacts of standard-efficiency technologies with those of alternative high-efficiency equipment. This, in turn, dictates a relatively detailed understanding of the energy characteristics of the marketplace. Baseline data that were required for each studied market segment includes:

- Total count of energy-consuming units (floor space of commercial buildings, number of residential dwellings, and the base kWh consumption of industrial facilities)
- Annual energy consumption for each end use studied (both in terms of total consumption in GWh and normalized for intensity on a per-unit basis (e.g., kWh/ft2)
- End-use load shapes (that describe the amount of energy used or power demand over certain times of the day and days of the year)
- The saturation of electric end uses (e.g., the fraction of total commercial floor space with electric air conditioning)
- The market share of each base equipment type for example, the fraction of total commercial floor space served by 4-foot fluorescent lighting fixtures)
- Market share for each energy-efficiency measure in scope (for example, the fraction of total commercial floor space already served by CFLs).

Data for the baseline analysis comes from a number of sources including baseline studies conducted by Missouri utilities, the Department of Energy's Energy Information Administration, the Federal Energy Regulatory Commission, federal and state government databases, Bureau of the Census, evaluations of Missouri efficiency programs, and a recent appliance saturation survey. Baseline data sources vary by sector and are described further below.

4.1.1 Energy Summary

To develop Missouri statewide energy use by sector, we started with breakouts from the Energy Information Administration's State Energy Data System (EIA's SEDS, found at http://www.eia.doe.gov/states/_seds.html). Table 4-1 shows the SEDS data by fuel and sector, with subtotals for the commercial and industrial (C&I) sectors combined. For natural gas, consumption is further broken out into sales and transport, a distinction which may be important for program design. For this study, we have been directed to consider both natural gas sales and transport for savings potential.

Table 4-1
SEDS Energy Consumption Data

	NG Trillion Btu	Electricity Million kWh
Residential consumption	114.6	35,390
Commercial consumption	65.3	31,118
Industrial consumption	67.1	17,850
Subtotal C&I	*132.4*	*48,968*
Commercial sales (excludes transport)	50.6	
Industrial sales (excludes transport)	9.3	
Subtotal C&I	*59.9*	
Coml Transport	14.7	
Ind transport	57.8	
Subtotal C&I	72.5	

It is our understanding that the SEDS sector breakouts are determined by assigning rate classes to one sector or another in their entirety. Utilities typically have a residential rate class that applies to residential customers, so this approach should result in accurate estimates for the residential sector. However, because commercial and industrial rates are typically broken out by customer demand rather than by sector, we did not want to rely on SEDS for the commercial industrial breakouts. Instead, while we relied on SEDS for overall C&I consumption, we looked for other data to break out energy use between the sectors.

We found that Ameren, KCP&L and KCP&L/GMO each had detailed commercial and industrial baseline electricity analyses, which were provided to us through the PSC. These three utilities represent a majority of Missouri's electricity consumption. While we had concerns extrapolating the data to Missouri as a whole, we felt this approach was more reliable than SEDS' rate-class approach. In the absence of detailed sector breakouts from Empire and the state's publicly owned utilities, we believe this is the best approach. Table 4-2 shows the adjusted electricity consumption by sector.

Table 4-2
Adjusted Energy Consumption Data

	Electricity Million kWh
Commercial consumption	28,577
Industrial consumption	20,391
Subtotal C&I	48,968

There were no similar baseline studies available from the natural gas utilities detailing the natural gas market. The variation between energy use profiles in different utilities, combined with the variation in industrial customers between utilities, regions, and states, limited our ability to leverage data from other studies. In the absence of a better approach, we adopted the SEDS splits for natural gas.

The resulting breakdowns of energy use by sector are shown in the charts below.

Figure 4-1
Electricity Consumption by Sector

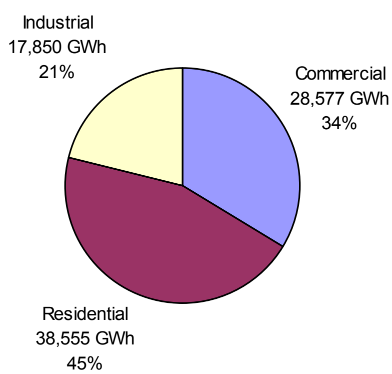
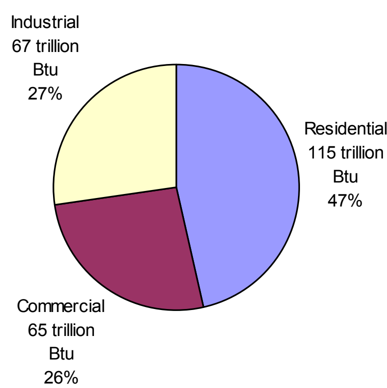


Figure 4-2
Natural Gas Consumption by Sector



The following sections discuss how usage was broken out further by building type and end use.

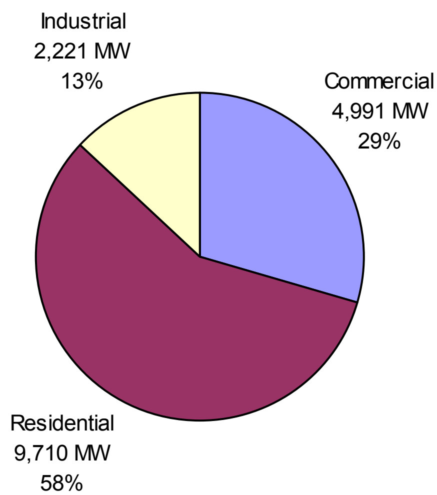
4.1.2 Peak Demand Summary

Peak demand estimates were calibrated to a forecast of Missouri's peak demand for 2011 from the Federal Energy Regulatory Commission's National Assessment of Demand Response

Potential, which estimates peak for the residential, commercial and industrial sectors at 16,922 MW.

The following figure shows our estimate of how system peak breaks out by sectors, which was based on our energy use estimates by building type and end-use (discussed below), and load shape data from the IOUs.

Figure 4-3
Contribution to Peak Demand by Sector



4.2 Electricity

4.2.1 Residential

4.2.1.1 Residential Building Types

The residential customer class in Missouri was disaggregated into four building types for our analysis:

- Single family (SF)
- Multifamily (MF)
- Single family low income (SF LI)

- Multifamily low income (MF LI)

While low income is not really a “building type,” it represents a customer segment that is frequently targeted with specialized programs. It is therefore useful to split these customers out in the modeling.

We prefer to break out energy use by building type using a billing data analysis, but because this is a statewide analysis involving a large number of utilities, billing data was not available. Instead, we turned to a variety of sources of secondary sources. The EIA’s most recent estimate of the total number of residential electricity customers in Missouri is 2,686,746. The total number of low income households (683,461) was taken from the “LIHEAP [Low Income Home Energy Assistance Program] Home Energy Notebook for Fiscal Year 2008.” This approach may understate the total number of low income households, as the figure is an average of the 2006 through 2008 state-level estimates. The ratio of low income single family and low income multifamily households was approximated using the American Community Survey 2009 dataset accessed through the Missouri Census Data Center's Data Extraction Web Utility “Dexter,” which allowed us to disaggregate Missouri into 41 regions. To inflate the energy consumption and customer counts from 2008 to 2011, ten year average growth rates of Missouri’s residential electricity and natural gas consumption and customer base from various EIA datasets were applied to the above quoted figures to arrive at the values used for this study, shown in Table 4-3. Table 4-4 shows the final residential customer counts by customer class.

Table 4-3
Residential Baseline and Forecast Figures

	Baseline	Source	Forecast 2011
Electric Customers	2,686,746	EIA 2008	2,789,874
Electric Consumption (MWh)	35,389,941	EIA 2008	38,554,849
Accounts Eligible for LIHEAP	683,461	2008 LIHEAP	700,840

Table 4-4
Number of Residential Customers by Class and Fuel (2011)

	SF	MF	SF-LI	MF-LI	Total
Electric	1,659,427	429,606	542,690	158,151	2,789,874

4.2.1.2 Residential Energy Consumption Survey Data

Energy consumption data and equipment saturations for the residential sector were taken from the EIA's Residential Energy Consumption Survey (RECS). The survey collects data on housing characteristics and energy consumption for more than 4,000 homes across the country.

Each home in the RECS dataset includes information about its location by census region and census divisions. Missouri falls into the "Midwest" region and the southeastern corner of the "West North Central" census division. As can be seen from the EIA maps below, these census divisions span disparate climate zones. To analyze weather sensitive end uses such as HVAC and water heating and capture both geographic and climate variations, we sorted the RECS microdata by census divisions, heating degree days (HDD) and cooling degree days (CDD). To approximate the climate in Missouri, microdata within divisions 3, 4, and 6 with the characteristics of climate zone 3 (less than 2,000 CDD and between 4,000 and 5,499 HDD) were selected for analysis. This dataset spans Missouri, Kansas, Kentucky, and the southern ends of Illinois and Indiana. For non-weather sensitive measures, we used data from the West North Central census division.

Figure 4-4
United States Census Regions and Divisions

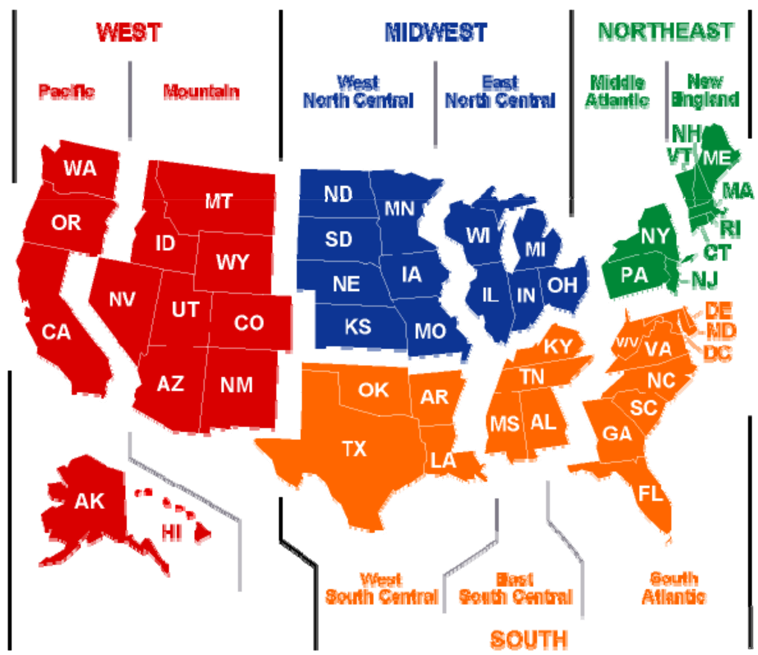
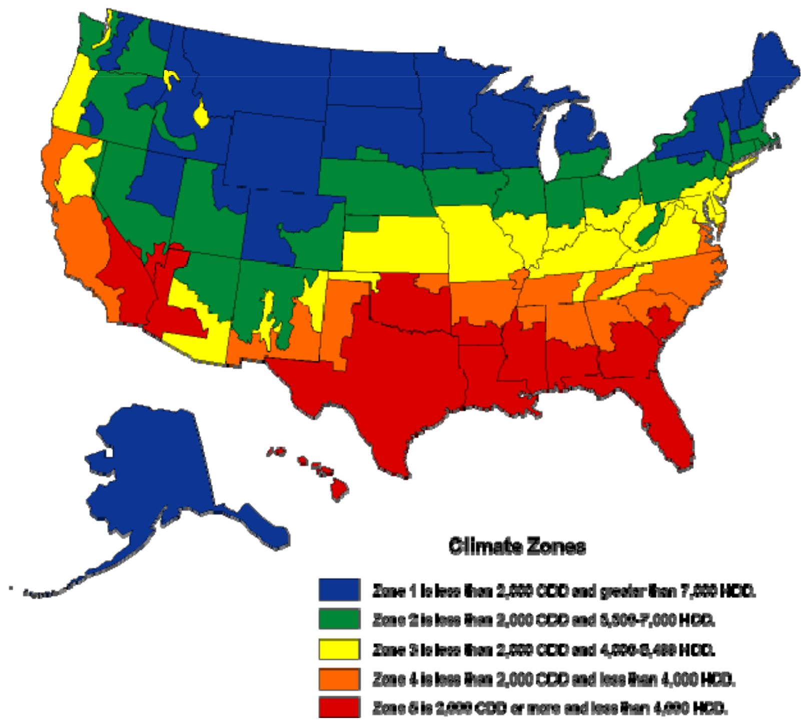


Figure 4-5
United States Climate Zones



4.2.1.3 Residential End use Saturations

Residential electric saturation were calculated based on RLW 2006, the 2010 Ameren UE "Demand Side Management Market Potential Study" by Global Energy Partners, and the Energy Information Administration's most recent Residential Energy Consumption Survey (RECS) microdata from 2005.

Table 4-5
Residential Electric End-Use Saturation

	SF	MF	SF LI	MF LI	Sources & Notes
10.7 SEER Split-System Air Conditioner	74.0%	73.1%	74.0%	73.1%	Ameren 2010 and RLW 2006 - 85% percentage of respondents with CAC.
Early Replace 10 SEER Split-Sys AC	13.1%	15.5%	13.1%	15.5%	Ameren 2010 and RLW 2006 - 15% respondents with CAC.
Room Air Conditioner - EER 9.7	5.1%	7.7%	5.1%	7.7%	Ameren 2010 and RLW 2006 - 85% percentage of respondents with RAC.
Early Replacement RAC- EER 9.0	0.9%	1.4%	0.9%	1.4%	Ameren 2010 and RLW 2006 - 15% of respondents with RAC.
Dehumidifier (EF =1.20)	27%	13%	27.0%	13.0%	Ameren 2010 --> all respondents with dehumidifier
Furnace Fans	87.0%	87.0%	87.0%	87.0%	RLW 2006
Resistance Space Heating	3.9%	3.9%	3.9%	3.9%	RLW 2006
Electric Furnace	15.0%	15.0%	15.0%	15.0%	RLW 2006
Ltg 60-Watt incandescent, 1.8 hr/day	100.0%	100.0%	100.0%	100.0%	RLW 2006
Lighting 15 Watt CFL, 1.8 hours/day	100.0%	100.0%	100.0%	100.0%	RLW 2006
Lighting Fluorescent Tube, 1.8 hrs/day	100.0%	100.0%	100.0%	100.0%	RLW 2006
Ltg: HID, Halogen, Fluor, 1.8 hrs/day	100.0%	100.0%	100.0%	100.0%	RLW 2006
Refrigerator (18 cf top-mount no TTD)	44.6%	44.6%	44.6%	44.6%	RLW 2006 --> 85% of 15-18.99 cf fridge with TF
Early Replacement of18 cf top mount	7.9%	7.9%	7.9%	7.9%	RLW 2006 --> 15% of 15-18.99 cf fridge with TF
Refrigerator (21 cf SS, no TTD)	40.4%	40.4%	40.4%	40.4%	RLW 2006 --> 85% of 19-21.99 cf fridge with SS
Early Replacement 21 cf SS	7.1%	7.1%	7.1%	7.1%	RLW 2006 --> 15% of 19-21.99 cf fridge with SS
Second Refrigerator	32.7%	12.0%	16.4%	6.0%	RLW 2006 for SF, Ameren 2010 for MF; LI estimated based on Ameren 2010
Freezer	45.9%	16.8%	38.3%	10.5%	RLW 2006 for SF, ratio to derive MF taken from SF/MF secondary fridge ownership --> 85% respondents with freezer; ; LI from ratios of SF LI/ SF and MF LI/ MF from RECS CZ 3, Division 3, 4 & 6
Early Replacement Freezer	8.1%	3.0%	8.1%	3.0%	RLW 2006 for SF, ratio to MF taken from SF/MF secondary fridge ownership -->15% respondents with freezer
40 gal. Water Heating (EF=0.88)	24.6%	33.4%	26.8%	28.9%	SF based on RLW 2006, assuming SF/MF ratio from Ameren, minus 5% from both for ER; LI from ratios of SF LI/ SF and MF LI/ MF from RECS CZ 3, Division 3, 4 & 6
Early Replacement Water Heating to Heat Pump Water Heater	1.3%	1.8%	1.4%	1.5%	SF based on RLW 2006, assuming SF/MF ratio from Ameren 2010, 5% from both for ER; LI from ratios of SF LI/ SF and MF LI/ MF from RECS CZ 3, Division 3, 4 & 6
Clothes washer (MEF=1.26)	98.0%	68.0%	98.0%	68.0%	Ameren 2010
Clothes Dryer (EF=3.01)	87.7%	63.8%	79.7%	57.8%	SF from RLW 2006, MF derived from ratio of SF/MF from Ameren 2010; LI from ratios of SF LI/ SF and MF LI/ MF from RECS CZ 3, Division 3, 4 & 6
Dishwasher (EF=0.65)	77.0%	75.0%	52.9%	31.5%	SF and MF from Ameren 2010, multiplied by the % of electric WH; LI from ratios of SF LI/ SF and MF LI/ MF from RECS CZ 3, Division 3, 4 & 6
Single Speed Pool Pump (RET)	0.4%	0.4%	0.0%	0.0%	RLW 2006; LI assumed to be 10%
Two Speed Pool Pump (1.5 hp) (ROB)	0.4%	0.4%	0.0%	0.0%	RLW 2006; LI assumed to be 10%
Plasma Screen TV	11.0%	8.0%	1.1%	0.8%	Ameren 2010 for SF/MF, assumption for LI
LCD Screen TV	42.0%	35.0%	4.2%	3.5%	Ameren 2010 for SF/MF, assumption for LI
Other TV	87.0%	78.0%	87.0%	78.0%	Ameren 2010 for SF/MF, assumption for LI
Laptop Computer	46.0%	56.0%	46.0%	56.0%	Ameren 2010
Desktop Computer	47.0%	35.0%	47.0%	35.0%	Ameren 2010
Cooking	81.4%	81.4%	81.4%	81.4%	RECS microdata, CZ 3 in Division 3, 4 & 6
Miscellaneous	100.0%	100.0%	100.0%	100.0%	By definition

4.2.1.4 Residential Energy Intensities

Residential sector end-use energy intensities are shown in Table 4-6. These were estimated from a variety of sources, as noted in the table.

Table 4-6
Residential Electric End-Use Energy Intensities (kWh/home with the installed measure)

	SF	MF	SF LI	MF LI	Sources & Notes
10.7 SEER Split-System Air Conditioner	3415	2433	3415	2433	ENERGYSTAR Calculator - SEER 10.7 (RLW 2006); St. Louis, MO; weighted average of 2.5 and 3 ton EUI for SF (RLW 2006 average tonnage is 2.84 ton), ratio of SF/MF floorspace for MF from Ameren 2010 Volume 3 Appendix B. Calibrated.
Early Replace 10 SEER Split-Sys AC	3638	2592	3638	2592	ENERGYSTAR Calculator- 3 ton for SF 2.5 ton for MF. 10 SEER, used ENERGYSTAR calculator for St. Louis, MO; Calibrated.
Room Air Conditioner - EER 9.7	1785	2293	1730	1441	ENERGYSTAR Calculator, 9.7 EER, St. Louis, MO; Units/ home from RECS microdata, CZ3 in Division 3, 4 & 6 Calibrated.
Early Replacement RAC-EER 9.0	1923	2470	1864	1553	ENERGYSTAR Calculator, 9.0 EER, St. Louis, MO; Units/ home from RECS microdata, CZ3 in Division 3, 4 & 6 Calibrated.
Dehumidifier (EF =1.20)	1064	1064	1064	1064	ENERGYSTAR Calculator- 35-45 pints, 1.2 EF
Furnace Fans	983	983	983	983	Assumed 350 watts, 1997 full load heating hours and 1178 cooling hours (ENERGYSTAR Calculator ASHP); Calibrated.
Resistance Space Heating	14,805	10,048	17,729	7,612	RECS microdata, CZ 3 in Division 3, 4 & 6. Note that LBNL "Home Energy Saver" gave preliminary heating estimates of 18,230 kWh/ yr for baseboard heat, using SF housing characteristics from Ameren 2010 Vol 3 Appendix B, St. Louis. Calibrated.
Electric Furnace	11,694	8,308	9,348	6,293	RECS microdata, CZ 3 in Division 3, 4 & 6. Note that LBNL "Home Energy Saver" gave preliminary heating estimates of 18,553 kWh/ yr for electric furnace heat, using SF housing characteristics from Ameren 2010 Vol 3 Appendix B, St. Louis. Calibrated.
Lighting 60-Watt incandescent, 1.8 hr/day	1528	860	1528	860	Hours of use (1.8 hrs/day) from CA Upstream Lighting Evaluation Program; lamps/HH and average watts/bulb from RLW 2006, updated to account for Ameren's findings that CFL and Halogen penetration has increased; incandescent is 37.22 bulbs/HH (63%) and 62.5 watts. MF diminished to account for Ameren's findings that MF averages 27/48 as many bulbs/HH as SF
Lighting 20 Watt CFL, 1.8 hours/day	172	97	172	97	Hours of use (1.8 hrs/day) from CA Upstream Lighting Evaluation Program; lamps/HH and average watts/bulb from RLW 2006, updated to account for Ameren's findings that CFL and Halogen penetration has increased; CFLs average 12.44 bulbs/HH (21%) and 21 watts. MF diminished to account for Ameren's findings that MF averages 27/48 as many bulbs/HH as SF
Lighting Fluorescent Tube, 1.8 hrs/day	83	46	83	46	Hours of use (1.8 hrs/day) from CA Upstream Lighting Evaluation Program; lamps/HH and average watts/bulb from RLW 2006, updated to account for Ameren's findings that CFL and Halogen penetration has increased; Fluorescent is 21.05W and 5.97 bulbs/home. MF diminished to account for Ameren's findings that MF averages 27/48 as many bulbs/HH as SF
Lighting HID, Halogen, 1.8 hrs/day	116	65	116	65	Hours of use (1.8 hrs/day) from CA Upstream Lighting Evaluation Program; lamps/HH and average watts/bulb from RLW 2006, updated to account for Ameren's findings that CFL and Halogen penetration has increased; Halogen is

Table 4-6

Residential Electric End-Use Energy Intensities (kWh/home with the installed measure)

					45.6W and 3.55 bulbs/home; HID is 251.9W and 0.06 bulbs/home. MF diminished to account for Ameren's findings that MF averages 27/48 as many bulbs/HH as SF
Refrigerator (18 cf top-mount no TTD)	878	777	878	777	RLW 2006, multiplied by fridges/home, taking into account fridges for recycling
Early Replacement of18 cf top mount	878	777	878	777	RLW 2006, multiplied by fridges/home, taking into account fridges for recycling
Refrigerator (21 cf SS, no TTD)	1,156	1,023	1,156	1,023	RLW 2006, multiplied by fridges/home, taking into account fridges for recycling
Early Replacement 21 cf SS	1,156	1,023	1,156	1,023	RLW 2006, multiplied by fridges/home, taking into account fridges for recycling
Second Refrigerator	791.4	791.4	791.4	791.4	RLW 2006
Freezer	549	549	549	549	RLW 2006
Early Replacement Freezer	549	549	549	549	RLW 2006
					DOE/LBNL Water Heater calculator; EF .89 (RLW 2006); gallons per day based on 21.78 gallons daily recovery load per person (PG&E 2007) multiplied by average people/ home 2.7 for SF and 1.9 for MF (Ameren 2010).
40 gal. Water Heating (EF=0.88)	4,516	3447	4516	3447	DOE Water calculator; EF .89 (RLW 2006); gallons per day based on 21.78 gallons daily recovery load per person (PG&E 2007) multiplied by average people/ home 2.7 for SF and 1.9 for MF (Ameren 2010).
Early Replacement Water Heating to Heat Pump Water Heater	4,516	3,447	4,516	3,447	ENERGYSTAR Calculator- Energy used with beyond water heating
Clothes washer (MEF=1.26)	80.7	81	81	81	Assumptions from [http://www.energy.ca.gov/2008publications/CEC-400-2008-013/CEC-400-2008-013-D.PDF] (653); [http://www.calmac.org/events/Final_DEER_Presentation_-_Complete_.ppt#347,29,Non-Weather Sensitive Measures; LBNL:Residential Measures; [http://enduse.lbl.gov/SharedData/standards/resstds.DOC]. Based on 416 cycles/yr SF and 250 cycles/yr MF; SF LI is average of SF and MF
Clothes Dryer (EF=3.01)	969	583	776	583	ENERGYSTAR Calculator
Dishwasher (EF=0.65)	162	162	162	162	Used CEC HERS EUI, then divided by 3.25 to account for less run time in MO than CA
Single Speed Pool Pump (RET)	822	822	822	822	Using pump affinity law: [http://clubp.info/media/1.Pool%20Pump%20Energy%20Savings%20Calculator.xls], then divided by 3.25 to account for less run time in MO
Two Speed Pool Pump (1.5 hp) (ROB)	357	357	357	357	Calculated from LBNL 4/2008 UEC for all TV types
Plasma Screen TV	931	1118	946	946	Calculated from LBNL 4/2008 UEC for all TV types
LCD Screen TV	450	500	460	460	Calculated from LBNL 4/2008 UEC for all TV types
Other TV	127	111	118	118	LBNL4/2007 UEC, adjusted by average number of laptops per home
Laptop Computer	192	168	170	170	LBNL4/2007 UEC, adjusted by average number of desktops/home

Table 4-6

Residential Electric End-Use Energy Intensities (kWh/home with the installed measure)

Desktop Computer	730	572	685	1129	CA HERS Topic Report 2008 - [http://www.energy.ca.gov/2008publications/CEC-400-2008-013/CEC-400-2008-013-D.PDF]
Cooking	316	316	316	316	Assumed 10%, calibrated to intensity targets
Miscellaneous	1536	1132	1434	1033	ENERGYSTAR Calculator - SEER 10.7 (RLW 2006); St. Louis, MO; weighted average of 2.5 and 3 ton EUI for SF (RLW 2006 average tonnage is 2.84 ton), ratio of SF/MF floorspace for MF from Ameren 2010 Volume 3 Appendix B

4.2.1.5 Residential Energy Use

The following tables and figures show the number of households by building type and energy consumption by building type and end-use for electricity. Energy use is calculated by multiplying together the saturations, EUIs, and number of households.

Table 4-7
Residential Electric Housing Stock and Energy Use by Building Type and End-Use

	SF	MF	SF LI	MF LI	Total
Households	1,659,427	429,606	542,690	158,151	2,789,874
Energy Consumption (MWh)					
10.7 SEER Split-System Air Conditioner	4,190,376	764,090	1,370,397	281,284	6,606,146
Early Replace 10 SEER Split-Sys AC	787,747	172,369	257,620	63,454	1,281,190
Room Air Conditioner - EER 9.7	151,039	75,349	47,894	17,435	291,717
Early Replacement RAC- EER 9.0	28,717	14,326	9,106	3,315	55,465
Dehumidifier (EF =1.20)	476,720	59,423	155,904	21,875	713,923
Furnace Fans	1,419,121	367,394	464,101	135,248	2,385,865
Resistance Space Heating	948,768	166,710	371,563	46,491	1,533,532
Electric Furnace	2,902,788	533,874	758,882	148,872	4,344,415
Ltg 60-Watt incandescent, 1.8 hr/day	2,535,853	369,283	829,311	135,944	3,870,390
Lighting 20 Watt CFL, 1.8 hours/day	284,824	41,477	93,147	15,269	434,718
Lighting Fluorescent Tube, 1.8 hrs/day	137,009	19,952	44,807	7,345	209,113
Ltg: HID, Halogen 1.8 hrs/day	193,185	28,133	63,178	10,356	294,853
Refrigerator (18 cf top-mount no TTD)	649,886	148,873	212,535	54,805	1,066,100
Early Replacement of 18 cf top mount	114,686	26,272	37,506	9,671	188,135
Refrigerator (21 cf SS, no TTD)	775,226	177,586	253,525	65,375	1,271,711
Early Replacement 21 cf SS	136,805	31,339	44,740	11,537	224,420
Second Refrigerator	429,440	40,799	70,221	7,510	547,969
Freezer	418,465	39,756	114,132	9,083	581,436
Early Replacement Freezer	73,847	7,016	24,150	2,583	107,596
40 gal. Water Heating (EF=0.88)	1,844,903	493,972	656,806	157,821	3,153,503
Early Replacement Water Heating to Heat Pump Water Heater	97,100	25,999	34,569	8,306	165,974
Clothes washer (MEF=1.26)	131,237	23,575	42,919	8,679	206,410
Clothes Dryer (EF=3.01)	1,410,203	159,611	335,707	53,282	1,958,803
Dishwasher (EF=0.65)	206,997	52,197	46,536	8,059	313,789
Single Speed Pool Pump (RET)	5,246	1,358	-	-	6,604
Two Speed Pool Pump (1.5 hp) (ROB)	2,280	590	-	-	2,870
Plasma Screen TV	169,942	38,407	5,648	1,197	215,194
LCD Screen TV	313,318	75,106	10,474	2,544	401,442
Other TV	182,989	37,028	55,854	14,593	290,464
Laptop Computer	146,511	40,528	42,484	15,072	244,596
Desktop Computer	568,989	85,982	174,628	62,467	892,066
Cooking	427,028	110,553	139,653	40,698	717,931
Miscellaneous	2,548,543	486,326	778,320	163,320	3,976,509

Figure 4-6
Residential Electricity Use by End Use

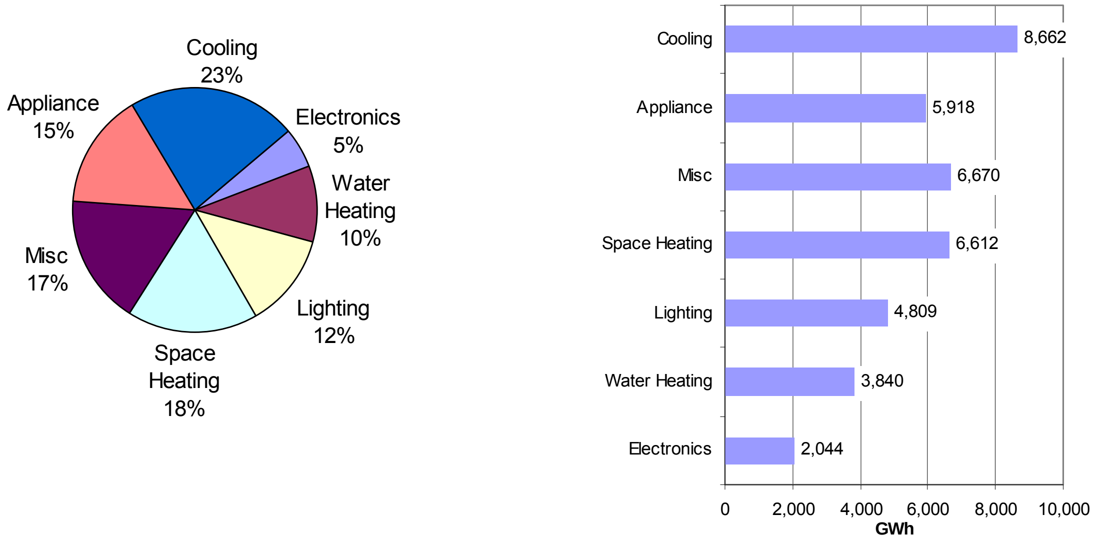
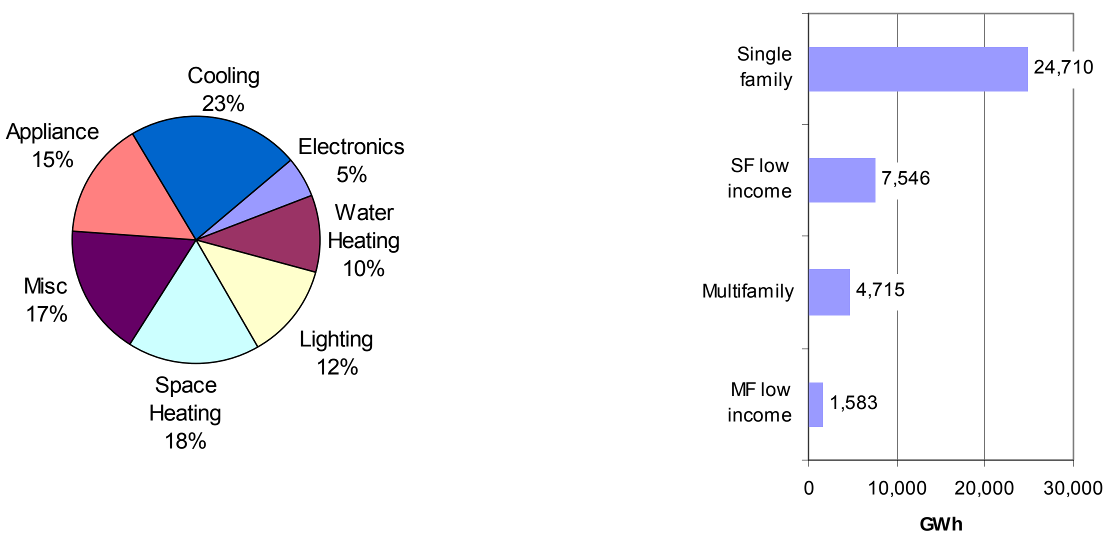


Figure 4-7
Residential Electricity use by Building Type



4.2.1.6 Residential Peak Demand

Residential load shape data from KEMA's end-use databases was utilized to allocate annual energy usage to time-of-use (TOU) periods. Peak period usage, developed on a sector-specific and end-use basis, were calibrated across all sectors to equal the Missouri summer peak. Residential peak demand was estimated to be 9,710 MW. The following table shows the contribution to residential peak demand by building type and end use.

Figure 4-8
Residential Peak Demand by Building Type and Sector (MW)

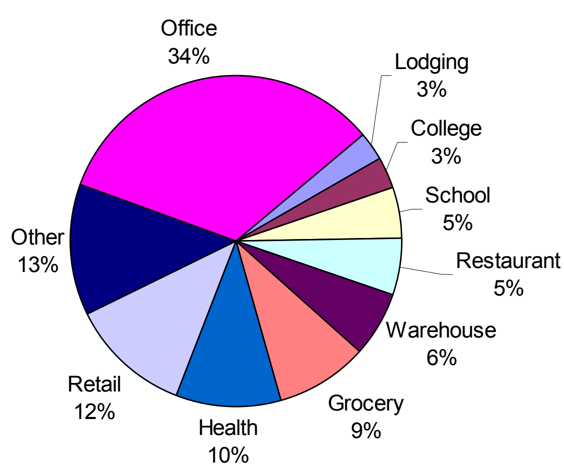
Peak demand estimates	SF	MF	SF LI	MF LI	Total
10.7 SEER Split-System Air Conditioner	2,941	536	962	197	4,637
Early Replacement 10 SEER Split-System AC	672	147	220	54	1,093
EER 9.7 Room Air Conditioner	129	64	41	15	249
Early Replacement Room Air Conditioner- EER 9.0 to CEE Tier 1 EER 11.3	24	12	8	3	47
Dehumidifier (35-45 pints/day; EF = 1.20)	118	15	39	5	176
Furnace Fans (Retrofit)	1,210	313	396	115	2,035
Resistance Space Heating (Electric)	0	0	0	0	0
Electric Furnace	0	0	0	0	0
Lighting 60 Watt Incandescent, 1.8 hours per day	142	21	46	8	216
Lighting 15 Watt CFL, 1.8 hours per day	16	2	5	1	24
Lighting Fluorescent Tube, 1.8 hrs/day	8	1	3	0	12
Lighting HID, Halogen, Fluorescent, 1.8 hrs per day	11	2	4	1	16
Refrigerator	83	22	27	8	140
Early Replacement Refrigerator	15	4	5	1	25
Second Refrigerator	35	3	6	1	45
Freezer	35	3	10	1	48
Early Replacement Freezer	6	1	2	0	9
40 gal. Water Heating (EF=0.90)	113	30	40	10	194
Early Replacement Water Heating to Heat Pump Water Heater	6	2	2	1	10
Clotheswasher (MEF=1.26)	11	2	4	1	17
Clothes Dryer (EF=.46)	112	13	27	4	155
Dishwasher (EF=0.58)	18	5	4	1	28
Single Speed Pool Pump to Variable RET	0	0	0	0	0
Two Speed Pool Pump to Variable ROB	0	0	0	0	0
Plasma Screen TV	13	3	0	0	17
LCD TV	24	6	1	0	31
Other TV	14	3	4	1	22
Laptop Computer	10	3	3	1	17
Desktop Computer	38	6	12	4	60
Cooking	70	18	23	7	117
Miscellaneous	172	33	52	11	269
House Practices	1,668	321	508	107	2,604
Total	6,047	1,269	1,944	451	9,710

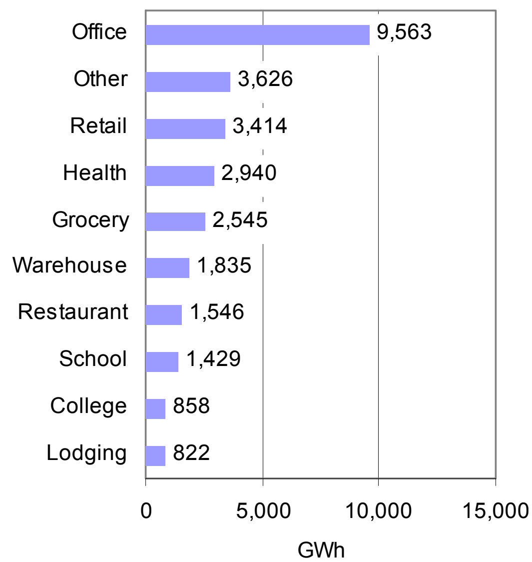
4.2.2 Commercial

4.2.2.1 Commercial Building Types

For the commercial electricity breakdown, we turned to the baseline studies performed by Ameren, KCP&L and KCP&L-GMO. The sales data by building type for the three utilities was combined and the resulting distribution of commercial electricity use by building type was applied to total Missouri consumption, developed as discussed above. Figure 4-9 shows the breakdown of commercial electricity use by building type.

Figure 4-9
Commercial Electricity Use by Building Type





4.2.2.2 Commercial End-use Saturations

For the commercial sector electricity saturations, we again turned to the commercial baseline estimates done for Ameren, KCP&L and KCP&L-GMO. Each study broke out energy use by major end-use (lighting, cooling, etc.). These end-use splits were weighted and used as the basis for the base measure saturations.

Because some end-uses have several base measures, we needed to break out the end-use saturations developed from the utility studies into the detailed base measures. To do this, we turned to detailed on-site data from a recent Rhode Island study (no Missouri data was found to inform these splits at the necessary level of detail). This allowed us to break up the overall cooling saturation, for example, into chillers and DX systems. During the EUI calibration process, discussed below, some saturations were modified so that energy intensities and end-use intensities would balance.

For some measures, the utility data was not available or useable (for example, outdoor lighting could not be disaggregated from indoor lighting). We turned to the U.S. DOE's Commercial Building Energy Consumption Survey (CBECS) for some measures that fell outside the definitions of the utility studies, and used saturations from previous studies for outdoor lighting. Exit signs and miscellaneous were assumed to have 100 percent saturation.

Commercial end-use saturations are shown in Table 4-8.

Table 4-8
Commercial Saturations for Electric Base Measures

	Office	Restaurant	Retail	Grocery	Warehouse	School	College	Health	Lodging	Other
Lighting 4 Lamp 4' T12	5.96%	8.0%	3.69%	0.00%	9.50%	0.00%	0.60%	0.46%	0.00%	3.41%
Lighting 2 Lamp 4' T12	9.94%	3.00%	7.48%	12.00%	6.04%	0.00%	0.98%	1.75%	1.90%	2.28%
Lighting 2 Lamp 8' T12	4.77%	8.00%	5.06%	50.39%	3.31%	0.00%	0.00%	0.00%	0.00%	0.97%
Lighting Incand-CFL Screw-in	15.80%	70.00%	9.70%	15.00%	0.47%	3.33%	0.63%	5.63%	4.73%	32.77%
Lighting CFL-LED Screw-in	5.48%	1.00%	0.47%	0.00%	0.79%	0.20%	0.01%	8.82%	8.70%	5.24%
Lighting Incand-CFL Hardwire	7.13%	7.00%	2.82%	3.00%	0.04%	0.22%	3.64%	15.50%	23.65%	7.20%
Lighting CFL-LED Hardwire	19.65%	1.00%	0.22%	0.51%	0.06%	0.14%	6.09%	25.33%	61.01%	5.71%
Lighting High Bay	0.65%	0.00%	8.22%	7.09%	6.00%	11.21%	2.75%	0.31%	0.00%	14.66%
Lighting 4 Lamp 4' T8	12.64%	1.00%	16.93%	0.00%	13.51%	30.05%	34.30%	39.57%	0.00%	18.89%
Lighting 2 Lamp 4' T8	18.28%	1.00%	35.85%	12.00%	3.93%	24.89%	48.74%	49.93%	0.00%	8.59%
Lighting Exit Signs	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Outdoor Lighting	67.00%	100.00%	81.50%	47.28%	88.72%	79.19%	100.00%	96.73%	100.00%	88.40%
Street Lighting										100.00%
Chillers	35.42%	4.55%	12.31%	0.00%	7.17%	21.36%	74.74%	76.68%	27.92%	14.57%
DX Packaged Systems	57.19%	88.17%	73.81%	94.29%	72.81%	62.64%	9.26%	18.01%	67.94%	69.92%
Ventilation Motors 5 hp	85.96%	72.75%	73.25%	49.25%	68.33%	77.68%	100.00%	47.74%	100.00%	83.57%
Ventilation Motors 15 hp	5.52%	12.09%	8.97%	0.00%	0.00%	42.03%	37.11%	14.33%	0.00%	12.15%
Ventilation Motors 40 hp	20.20%	0.00%	13.64%	0.00%	5.70%	0.00%	22.29%	0.00%	0.00%	52.04%
Non-commercial refrigerators	67.29%	44.01%	53.11%	43.40%	49.04%	60.32%	73.12%	89.74%	61.09%	60.04%
Refrigeration System	67.82%	87.69%	70.06%	96.67%	67.13%	86.43%	97.23%	96.55%	86.10%	63.53%
Desktop PC	91.03%	72.75%	84.39%	66.98%	68.10%	93.00%	37.11%	94.91%	96.41%	79.14%
Monitor, 17" CRT	38.85%	31.45%	54.86%	37.43%	71.20%	69.18%	37.11%	42.19%	4.90%	63.53%
Monitor, 17" LCD	16.74%	46.96%	12.77%	61.73%	15.55%	84.00%	37.11%	24.80%	63.47%	22.82%
Copier	94.22%	14.22%	58.98%	45.73%	68.10%	85.66%	93.00%	94.91%	42.36%	49.16%
Laser Printer	94.22%	72.60%	85.82%	87.64%	68.10%	93.00%	93.00%	94.91%	86.05%	65.72%
Data Centers	0.72%	0.10%	0.03%	0.13%	0.18%	0.31%	1.28%	1.10%	0.07%	0.11%
Water Heating	36.08%	21.17%	35.19%	8.09%	30.88%	27.00%	27.00%	9.20%	8.04%	34.66%
Vending Machines	62.30%	25.04%	48.54%	53.64%	51.98%	71.69%	96.62%	95.93%	84.03%	36.91%
Convection Oven	0.00%	67.93%	12.77%	38.58%	0.00%	84.00%	84.00%	0.00%	63.47%	22.82%
Fryer	1.43%	21.41%	0.00%	38.58%	0.00%	0.00%	0.00%	0.00%	0.00%	22.82%
Steamer	1.43%	38.11%	0.00%	61.73%	0.00%	0.00%	0.00%	24.80%	0.00%	22.82%
Hot Food Holding Cabinets	1.43%	67.93%	6.45%	50.97%	0.00%	65.45%	65.45%	24.80%	49.75%	22.82%
Heating	20.93%	17.00%	19.55%	11.63%	14.94%	9.00%	9.00%	6.08%	56.59%	22.77%
Miscellaneous	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

4.2.2.3 Commercial Energy Intensity

The Ameren, KCP&L and KCP&L-GMO studies provided both energy intensities (energy per total building square foot) and end-use energy intensities (EUI, defined as energy use per end-use square foot) only for electricity. As with saturations, these were provided for major end-uses (such as lighting) rather than at the detailed base-measure level required for ASSYST. We therefore started with EUIs from a recent Colorado study, then adjusted within each major end-use category to match the Missouri data. Once that was done, we calculated the overall energy intensity by building type implied by the EUIs and saturation we had just developed. A second calibration was applied to bring the overall energy intensity in line with that found by the utility studies. We compared the results to the California Commercial End-Use Survey (CEUS) as a cross-check, and found, as expected, that energy use by non-weather-sensitive measures (such as lighting and cooking) were similar, while weather sensitive measures such as cooling and heating were higher in Missouri, which has more extreme weather than mild California.

Table 4-9
Commercial Electric EUIs (kWh/end-use square foot)

	Office	Restaurant	Retail	Grocery	Warehouse	School	College	Health	Lodging	Other
Lighting 4 Lamp 4' T12	2.9	2.3	3.5	8.3	2.9	4.6	4.2	3.6	2.1	1.1
Lighting 2 Lamp 4' T12	2.8	2.0	3.4	8.2	3.5	4.9	4.2	3.1	2.0	0.8
Lighting 2 Lamp 8' T12	2.8	2.0	3.4	8.2	3.5	4.9	4.2	3.1	2.0	0.8
Lighting Incand-CFL Screw-in	11.2	8.1	13.4	32.6	14.1	19.6	16.6	12.2	8.0	3.3
Lighting CFL-LED Screw-in	3.1	2.2	3.7	8.9	3.9	5.4	4.5	3.3	2.2	0.9
Lighting Incand-CFL Hardwire	11.2	8.1	13.4	32.6	14.1	19.6	16.6	12.2	8.0	3.3
Lighting CFL-LED Hardwire	3.1	2.2	3.7	8.9	3.9	5.4	4.5	3.3	2.2	0.9
High Bay Lighting	2.1	1.5	2.5	6.1	2.7	3.7	3.1	2.3	1.5	0.6
Lighting 4 Lamp 4' T8	1.9	1.4	2.2	5.5	2.4	3.3	2.8	2.0	1.3	0.6
Lighting 2 Lamp 4' T8	1.9	1.4	2.2	5.5	2.4	3.3	2.8	2.0	1.3	0.6
Exit Signs	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outdoor lighting	1.1	2.9	1.0	1.7	0.4	0.8	0.2	0.3	0.5	0.6
Street Lighting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.96
Chillers	2.9	5.3	2.3	5.9	2.5	1.5	2.1	3.1	0.9	1.1
DX Packaged Systems	4.9	9.1	4.0	10.2	4.3	2.5	3.6	5.3	1.6	1.9
Ventilation Motors 5 hp	1.1	3.1	0.9	7.8	0.7	0.8	0.6	3.9	0.7	0.4
Ventilation Motors 15 hp	1.0	2.9	0.8	7.2	0.6	0.7	0.5	3.6	0.7	0.4
Ventilation Motors 40 hp	1.0	2.8	0.8	7.1	0.6	0.7	0.5	3.5	0.7	0.4
Non-commercial refrigerators	0.1	0.3	0.1	0.0	0.0	0.2	0.0	0.1	0.2	0.0
Refrigeration System	0.1	10.3	0.3	26.4	1.3	0.4	0.5	0.3	0.4	0.2
Desktop PC	1.3	0.1	0.3	0.2	0.1	0.3	0.1	0.4	0.1	0.5
Monitor, 17" CRT	1.3	0.1	0.3	0.2	0.1	0.3	0.1	0.4	0.1	0.5
Monitor, 17" LCD	0.005	0.001	0.001	0.001	0.000	0.001	0.000	0.001	0.000	0.002
Copier	0.4	0.1	0.2	0.3	0.0	0.1	0.0	0.2	0.0	0.3
Laser Printer	0.8	0.2	0.4	0.2	0.1	0.2	0.0	0.4	0.1	0.4
Data Centers	236.0	265.8	282.2	407.5	25.9	94.6	75.2	118.3	194.9	116.2
Water Heating	0.5	5.8	0.8	5.5	0.4	0.4	0.4	1.3	3.2	0.5
Vending Machines	0.2	0.2	0.1	0.4	0.2	0.4	0.4	0.1	0.2	0.1
Convection Oven	0.0	0.7	0.2	1.3	0.0	0.0	0.0	0.0	0.0	0.1
Fryer	0.1	19.2	0.0	11.2	0.0	0.0	0.0	0.0	0.0	0.5
Steamer	0.1	6.6	0.0	4.3	0.0	0.0	0.0	0.4	0.0	0.3
Hot Food Holding Cabinets	0.0	1.1	0.6	1.5	0.0	0.0	0.0	0.1	0.1	0.1
Heating	5.5	6.4	4.3	9.5	1.0	6.4	6.4	7.0	2.4	2.3
Miscellaneous	4.1	4.5	2.4	5.0	0.6	0.37	0.37	8.9	2.9	2.2
Overall Energy Intensity (kWh/total sq ft)	20.57	45.06	13.42	67.88	7.53	9.37	9.43	24.10	11.89	9.92

4.2.2.4 Commercial Floorspace

Floorspace was calculated for electricity customers based on the saturations, EUIs and usage by building type already developed. Data on floorspace is poor, and we have typically found this data to be the least reliable of the inputs to the ASSYST baseline analysis. We therefore relied on the other data, and derived the floorspace that makes the other inputs balance in the final calibration step.

Floorspace is shown with energy consumption in Table 4-10.

4.2.2.5 Commercial Energy Consumption

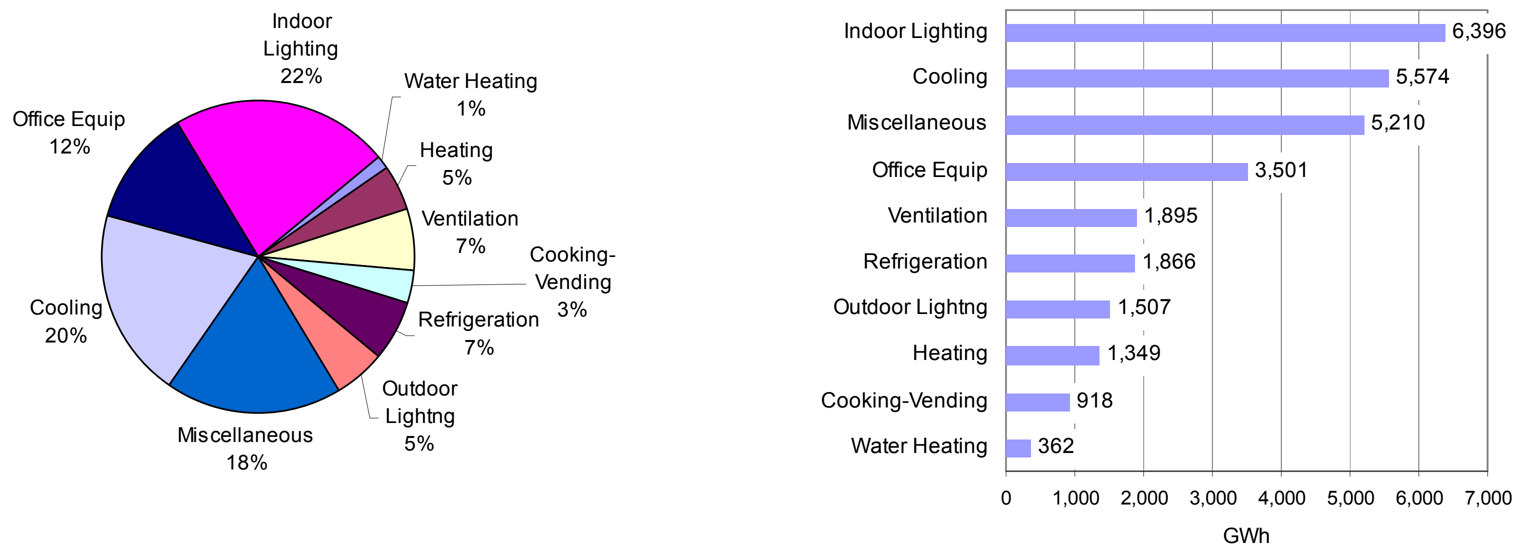
Table 4-10 shows commercial floorspace by building type and electricity consumption by end-use and building type. Figure 4-10 summarizes energy consumption by end-use.

Table 4-10

Commercial Floorspace (thousand sq ft) and Electricity Consumption (MWh) by Building Type and End Use

	Office	Restaurant	Retail	Grocery	Warehouse	School	College	Health	Lodging	Other	Total
Floorspace (thousand sq ft)	464,984	34,314	254,315	37,486	243,553	152,484	91,054	122,011	69,170	365,445	1,824,503
Energy Consumption (MWh)											
Lighting 4 Lamp 4' T12	81,024	6,254	33,065	0	66,871	0	2,321	2,025	0	13,188	204,747
Lighting 2 Lamp 4' T12	129,801	2,088	64,052	36,790	52,001	0	3,694	6,527	2,644	7,007	304,605
Lighting 2 Lamp 8' T12	62,352	5,569	43,294	154,487	28,493	0	0	0	0	2,984	297,180
Lighting Incand-CFL Screw-in	822,708	194,275	331,099	183,338	16,259	99,252	9,559	83,544	26,172	401,081	2,167,286
Lighting CFL-LED Screw-in	78,036	759	4,366	0	7,421	1,608	33	35,818	13,181	17,534	158,756
Lighting Incand-CFL Hardwire	371,605	19,427	96,185	36,668	1,210	6,680	54,937	230,186	130,860	88,082	1,035,840
Lighting CFL-LED Hardwire	280,000	759	2,013	1,715	552	1,133	25,160	102,928	92,390	19,118	525,770
High Bay Lighting	6,353	0	52,799	16,308	38,784	62,879	7,804	859	0	33,766	219,551
Lighting 4 Lamp 4' T8	110,057	464	96,635	0	77,599	149,848	86,620	98,248	0	38,662	658,134
Lighting 2 Lamp 4' T8	159,200	464	204,679	24,527	22,566	124,134	123,083	123,982	0	17,578	800,212
Exit Signs	6,927	1,993	3,695	414	940	1,606	2,055	3,315	1,723	1,131	23,799
Outdoor lighting	356,153	99,093	208,288	29,364	79,310	101,898	17,835	36,016	32,648	194,983	1,155,587
Street Lighting	0	0	0	0	0	0	0	0	0	351,323	351,323
Chillers	470,227	8,246	72,505	0	43,170	47,637	142,432	286,426	17,955	59,541	1,148,139
DX Packaged Systems	1,315,914	276,802	753,488	359,605	760,003	242,083	30,571	116,593	75,725	495,145	4,425,930
Ventilation Motors 5 hp	441,565	77,656	164,295	143,842	111,227	90,382	52,378	224,583	49,986	126,038	1,481,952
Ventilation Motors 15 hp	26,266	11,963	18,655	0	0	45,329	18,018	62,482	0	16,993	199,706
Ventilation Motors 40 hp	94,603	0	27,899	0	8,464	0	10,642	0	0	71,542	213,150
Non-commercial refrigerators	25,114	5,278	9,498	561	1,847	14,230	594	13,910	10,531	9,017	90,582
Refrigeration System	24,741	310,720	52,616	956,136	211,857	58,963	43,112	38,545	25,118	53,877	1,775,684
Desktop PC	541,511	3,446	65,779	4,292	15,144	46,196	2,367	45,338	3,720	145,178	872,970
Monitor, 17" CRT	226,284	1,458	41,869	2,348	15,502	33,642	2,318	19,730	185	114,096	457,433
Monitor, 17" LCD	379	8	38	15	13	159	9	45	9	159	834
Copier	184,766	417	30,707	5,492	5,820	9,472	1,183	28,643	789	47,036	314,326
Laser Printer	359,477	5,538	88,367	6,634	10,973	28,755	3,952	51,232	4,017	99,213	658,158
Data Centers	792,982	9,430	18,017	19,406	11,163	44,935	87,599	158,570	9,833	44,845	1,196,780
Water Heating	77,117	42,085	70,270	16,807	32,973	18,298	10,927	14,701	17,969	60,465	361,612
Vending Machines	64,130	1,678	9,643	8,797	26,615	49,039	32,780	7,910	9,496	15,535	225,622
Convection Oven	0	15,797	6,458	18,242	0	2,282	0	0	1,163	4,444	48,387
Fryer	760	140,677	0	162,452	0	0	0	0	0	39,578	343,467
Steamer	467	86,451	0	99,833	0	0	0	10,826	0	24,322	221,899
Hot Food Holding Cabinets	134	24,727	10,109	28,555	0	3,573	0	3,096	1,821	6,957	78,971
Heating	538,504	37,296	212,864	41,489	35,199	88,441	52,812	52,117	95,629	194,734	1,349,085
Miscellaneous	1,913,422	155,200	620,438	186,614	152,795	56,419	33,690	1,082,007	198,927	810,470	5,209,982
Total	9,562,578	1,546,022	3,413,686	2,544,730	1,834,769	1,428,873	858,486	2,940,201	822,491	3,625,623	28,577,458

Figure 4-10
Commercial Electricity Consumption by End Use



4.2.2.6 Commercial Peak Demand

Commercial load shape data from KEMA's end-use databases was utilized to allocate annual energy usage to time-of-use (TOU) periods. Peak period usage, developed on a sector-specific and end-use basis, were calibrated across all sectors to equal the Missouri summer peak. Commercial peak demand was estimated to be 4,991 MW. The table below shows the contribution to commercial peak demand by building type and end use.

Table 4-11

Commercial Peak Demand by Building Type and End Use (MW)

	Office	Restaurant	Retail	Grocery	Warehouse	School	College	Health	Lodging	Other	Total
Lighting 4 Lamp 4' T12	10.1	0.8	4.0	0.0	7.9	0.0	0.3	0.2	0.0	1.5	24.8
Lighting 2 Lamp 4' T12	16.1	0.3	7.7	3.7	6.1	0.0	0.5	0.7	0.2	0.8	36.2
Lighting 2 Lamp 8' T12	7.8	0.7	5.2	15.7	3.4	0.0	0.0	0.0	0.0	0.3	33.1
Lighting Incand-CFL Screw-in	102.3	25.5	39.9	18.6	1.9	9.1	1.4	8.5	2.5	45.6	255.2
Lighting CFL-LED Screw-in	9.7	0.1	0.5	0.0	0.9	0.1	0.0	3.6	1.2	2.0	18.2
Lighting Incand-CFL Hardwire	46.2	2.6	11.6	3.7	0.1	0.6	7.8	23.4	12.3	10.0	118.3
Lighting CFL-LED Hardwire	34.8	0.1	0.2	0.2	0.1	0.1	3.6	10.4	8.7	2.2	60.4
High Bay Lighting	0.8	0.0	6.4	1.7	4.6	5.7	1.1	0.1	0.0	3.8	24.2
Lighting 4 Lamp 4' T8	13.7	0.1	11.7	0.0	9.2	13.7	12.2	10.0	0.0	4.4	74.9
Lighting 2 Lamp 4' T8	19.8	0.1	24.7	2.5	2.7	11.3	17.4	12.6	0.0	2.0	93.0
Exit Signs	1.1	0.3	0.6	0.1	0.1	0.3	0.3	0.5	0.3	0.2	3.8
Outdoor lighting	3.3	4.4	9.1	0.5	0.7	2.7	0.0	0.2	0.2	10.1	31.1
Street Lighting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.1	18.1
Chillers	215.3	3.2	37.6	0.0	26.3	15.3	54.5	100.5	6.8	30.6	490.1
DX Packaged Systems	602.6	108.4	391.0	149.4	462.4	77.7	11.7	40.9	28.5	254.2	2,126.8
Ventilation Motors 5 hp	84.7	12.6	28.9	19.4	21.7	11.0	9.2	28.6	6.7	22.9	245.7
Ventilation Motors 15 hp	5.0	1.9	3.3	0.0	0.0	5.5	3.2	8.0	0.0	3.1	30.0
Ventilation Motors 40 hp	18.1	0.0	4.9	0.0	1.6	0.0	1.9	0.0	0.0	13.0	39.6
Non-commercial refrigerators	2.6	0.6	1.1	0.1	0.3	1.5	0.1	1.5	1.1	1.0	9.7
Refrigeration System	2.6	34.4	5.9	114.2	29.9	6.0	4.8	4.1	2.7	6.0	210.7
Desktop PC	50.1	0.4	7.8	0.5	1.7	2.7	0.3	4.3	0.4	14.8	83.0
Monitor, 17" CRT	20.9	0.2	5.0	0.3	1.7	1.9	0.3	1.9	0.0	11.7	43.9
Monitor, 17" LCD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Copier	17.1	0.1	3.7	0.7	0.6	0.5	0.1	2.7	0.1	4.8	30.4
Laser Printer	33.3	0.7	10.5	0.8	1.2	1.7	0.5	4.9	0.4	10.1	64.0
Data Centers	73.4	1.2	2.1	2.3	1.2	2.6	10.4	15.0	1.0	4.6	114.0
Water Heating	6.9	4.8	7.5	1.8	3.4	1.0	1.4	1.3	1.6	6.0	35.7
Vending Machines	6.2	0.2	1.1	0.9	3.3	2.9	4.1	0.7	1.0	1.7	22.4
Convection Oven	0.0	2.2	0.8	1.7	0.0	0.1	0.0	0.0	0.2	0.5	5.4
Fryer	0.1	19.2	0.0	15.1	0.0	0.0	0.0	0.0	0.0	4.4	38.7
Steamer	0.0	11.8	0.0	9.3	0.0	0.0	0.0	1.4	0.0	2.7	25.2
Hot Food Holding Cabinets	0.0	3.4	1.2	2.6	0.0	0.2	0.0	0.4	0.2	0.8	8.8
Heating	24.6	0.1	1.0	0.0	0.0	1.2	3.0	1.9	1.8	3.4	36.9
Miscellaneous	185.8	20.3	73.9	19.8	19.2	3.4	4.2	100.4	21.4	90.3	538.7
Total	1,615.1	260.6	709.0	385.4	612.3	178.9	154.3	388.7	99.5	587.6	4,991.2

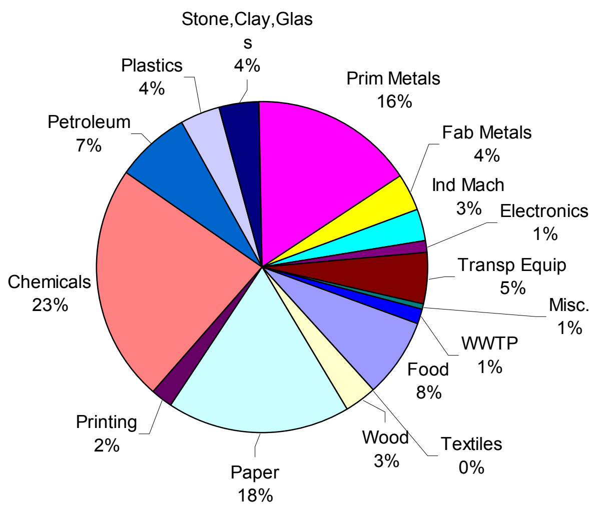
4.2.3 Industrial

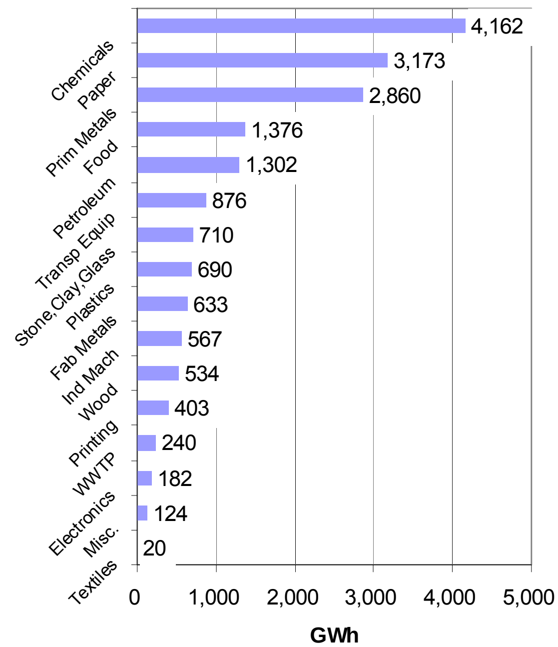
4.2.3.1 Industrial Building Types

We used a different approach on the industrial side. The available data on energy use by industry was not very detailed. The Ameren potential study treated all industries together to protect the confidentiality of Ameren's largest customers. The KCP&L and KCP&L-GMO studies broke out a limited number of industries (for example, printing and petroleum), while presenting all manufacturing industries together. Since we wanted to break out 16 different industries, this data was inadequate, although it acted as a cross-check against numbers developed through other methods. As noted above, the distribution of industries varies greatly by region, making it impossible to apply distributions from other studies as we did with commercial gas.

We adopted an approach based on employment data by industry. The Bureau of the Census' 2007 Economic Census provides state-level employment by NAICS code, which we combined with energy use per employee by industry from the Department of Energy's Manufacturing Energy Consumption Survey to estimate distributions of electricity and gas use by industry for Missouri. These were then normalized to the consumption estimates developed above. The following figures show the breakdown of electricity and natural gas by industry.

Figure 4-11
Industrial Sector Electricity Consumption by Industry





4.2.3.2 Industrial Sector End Use Consumption

Energy use was disaggregated into end-use consumption percentages based mainly on the Department of Energy's Manufacturing Energy Consumption Survey (MECS). Where possible, the most current end-use by industry splits were used. A minority of end use splits were withheld in the 2006 MECS due to sampling errors, and were informed by applying ratios derived from 2002 MECS end-use data. Further disaggregation of the motor end uses (into pumps, fans, drives, and compressed air) by industry were based on the 1998 study "United States Industrial Electric Motor Systems Market Opportunities Assessment." Water and wastewater treatment plant electric end-use splits are not included in MECS and were based on a number of surveys conducted during the course of KEMA's potential studies for Xcel Energy (Colorado) in 2004 and Rhode Island in 2010.

Table 4-12 shows, for each industry, the fraction of energy used by each end use. Figure 4-12 summarized industrial energy use by end use. Table 4-13 shown the full breakdown of industrial energy use by end-use and industry.

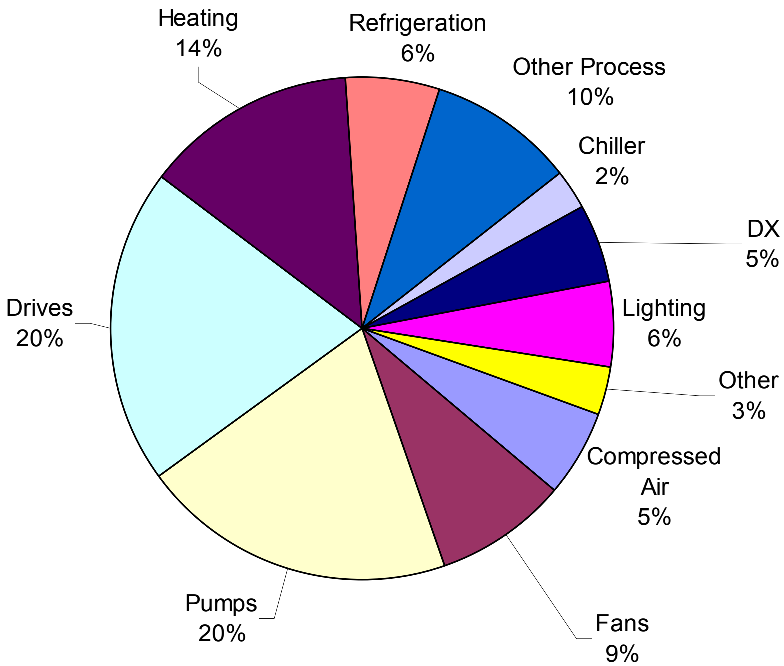
Table 4-12

Industrial Electric End-Use Consumption Splits (fraction of energy)

	Proc Heat	Proc Cool	Pumps	Fans	Comp Air	Proc Drives	Proc Other	HVAC	Lighting	Other	Boiler Use	CHP Proc	Total
Food	0.06	0.26	0.15	0.08	0.08	0.14	0.01	0.08	0.07	0.04	0.03	0.00	1.00
Textiles	0.10	0.12	0.09	0.07	0.04	0.30	0.01	0.14	0.10	0.03	0.01	0.00	1.00
Wood	0.07	0.01	0.11	0.09	0.05	0.41	0.01	0.07	0.08	0.09	0.02	0.00	1.00
Paper	0.04	0.02	0.24	0.15	0.04	0.32	0.02	0.04	0.04	0.02	0.07	0.00	1.00
Printing	0.03	0.06	0.09	0.07	0.04	0.32	0.01	0.19	0.12	0.07	0.01	0.00	1.00
Chemicals	0.05	0.08	0.26	0.06	0.03	0.21	0.14	0.06	0.04	0.03	0.04	0.00	1.00
Petroleum	0.04	0.05	0.49	0.07	0.12	0.13	0.01	0.04	0.02	0.01	0.01	0.00	1.00
Plastics	0.15	0.09	0.09	0.07	0.04	0.31	0.02	0.11	0.09	0.04	0.01	0.00	1.00
Stone,Clay,Glass	0.22	0.03	0.18	0.14	0.06	0.20	0.03	0.06	0.05	0.03	0.00	0.00	1.00
Prim Metals	0.28	0.01	0.10	0.08	0.03	0.11	0.31	0.03	0.03	0.01	0.00	0.00	1.00
Fab Metals	0.20	0.04	0.09	0.07	0.12	0.22	0.05	0.10	0.09	0.03	0.00	0.00	1.00
Ind Mach	0.07	0.03	0.07	0.05	0.14	0.18	0.02	0.22	0.15	0.06	0.00	0.00	1.00
Electronics	0.15	0.09	0.04	0.03	0.10	0.09	0.08	0.24	0.12	0.07	0.01	0.00	1.00
Transp Equip	0.14	0.06	0.07	0.05	0.12	0.12	0.03	0.19	0.15	0.05	0.01	0.00	1.00
Misc.	0.10	0.06	0.04	0.03	0.09	0.16	0.02	0.25	0.17	0.08	0.00	0.00	1.00
WWTP	0.01	0.00	0.62	0.30	0.00	0.00	0.00	0.02	0.04	0.00	0.00	0.00	1.00

Sources: DOE 2006 & 2003 MECS, KEMA 1998 Motors Assessment

Figure 4-12
Industrial Electricity Consumption by End Use



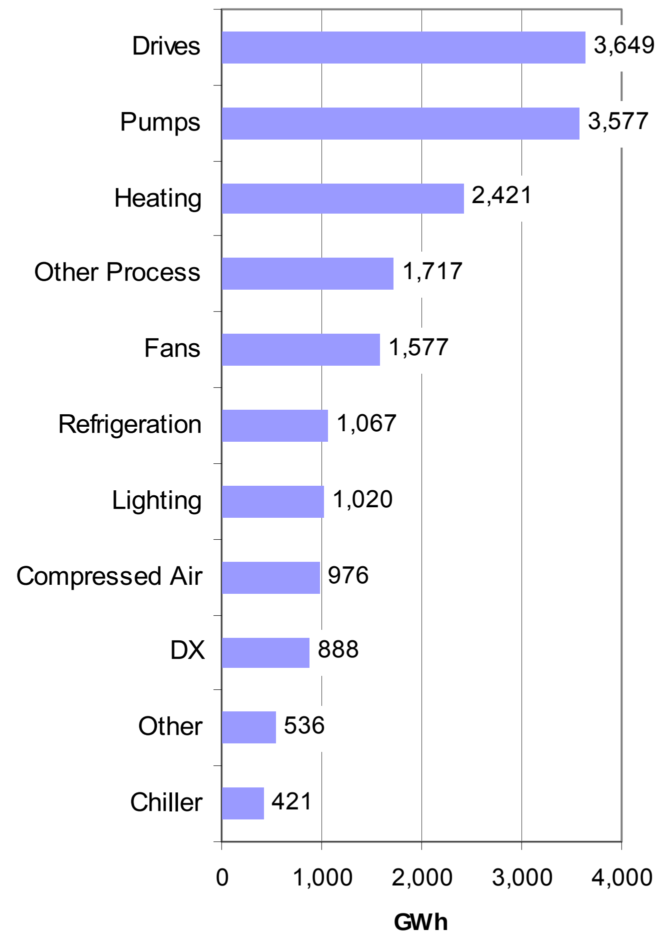


Table 4-13

Industrial Electricity Consumption by Industry and End Use (MWh)

	Compressed Air	Fans	Pumps	Drives	Heating	Refrig-eration	Other Process	Chiller	DX	Lighting	Other	Total
Food	104,793	114,696	201,829	193,927	113,119	357,270	13,761	14,928	101,526	101,576	58,345	1,375,767
Textiles	685	1,297	1,736	5,939	2,043	2,276	291	1,424	1,225	2,040	590	19,546
Wood	24,224	45,853	60,128	216,288	49,563	7,170	4,296	19,106	16,438	45,029	45,783	533,878
Paper	113,718	461,764	768,459	1,009,679	369,567	50,098	65,759	17,571	119,504	124,817	71,940	3,172,875
Printing	14,599	27,633	36,236	130,345	14,627	23,770	3,099	40,530	34,870	48,655	28,666	403,030
Chemicals	106,083	269,088	1,091,877	871,949	386,494	332,581	598,147	31,422	213,708	152,677	107,625	4,161,652
Petroleum	160,135	96,081	640,539	170,810	65,453	70,431	7,251	5,937	40,382	30,302	14,567	1,301,887
Plastics	24,251	45,903	60,194	216,525	110,184	62,045	11,670	39,811	34,252	59,098	26,467	690,399
Stone,Clay,Glass	42,157	99,069	125,769	142,632	155,528	19,165	23,608	5,692	38,715	36,649	21,513	710,497
Prim Metals	91,302	214,560	272,385	308,906	818,433	26,046	899,308	12,318	83,776	98,484	34,095	2,859,613
Fab Metals	74,991	41,769	54,772	138,733	126,362	22,282	30,193	34,103	29,340	59,443	20,933	632,921
Ind Mach	81,529	29,520	38,710	103,810	39,617	15,923	14,086	67,783	58,317	82,455	35,387	567,135
Electronics	18,320	5,551	7,280	15,572	27,705	15,713	14,091	23,228	19,984	21,035	13,160	181,639
Transp Equip	107,556	48,153	63,144	103,715	126,984	54,728	29,564	89,959	77,396	127,758	46,820	875,778
Misc.	11,036	4,099	5,375	20,032	12,552	7,329	1,890	16,391	14,102	20,648	10,113	123,566
WWTP	600	71,826	148,817	0	2,998	600	0	692	4,704	9,581	0	239,817
Total	975,977	1,576,863	3,577,249	3,648,861	2,421,229	1,067,426	1,717,014	420,894	888,237	1,020,246	536,004	17,850,000

4.2.3.3 Industrial Peak Demand

Industrial load shape data from KEMA's end-use databases were utilized to allocate annual energy usage to Missouri's peak electricity use periods. Given limited information on industrial end use load shapes, typical whole-facility shapes were applied to each end use. Peak period usage, developed on a sector-specific and end-use basis, were calibrated to equal Missouri's summer peak. Peak demands for the process cooling/refrigeration and HVAC end uses were adjusted upward to account for temperature sensitivity on peak days. Industrial peak demand was estimated to be 2,221 MW. Table 4-14 shows the contribution to peak by industry and end-use.

Table 4-14
Industrial Electric Peak Demand by Industry and End Use – MW – 2011

Peak demand estimates	Proc Heat	Proc Cool	Pumps	Fans	Comp Air	Proc Drives	Proc Other	HVAC	Lighting	Other	Boiler Use	CHP Proc	Total
Food	9.5	51.7	24.4	13.8	12.6	23.4	1.7	16.9	12.3	7.0	4.2	0.0	177.5
Textiles	0.8	1.1	0.7	0.5	0.3	2.5	0.1	1.3	0.8	0.2	0.1	0.0	8.5
Lumber	5.7	1.3	8.9	6.8	3.6	32.1	0.6	6.3	6.7	6.8	1.7	0.0	80.6
Paper	10.7	4.8	61.4	36.9	9.1	80.7	5.3	13.1	10.0	5.8	18.9	0.0	256.6
Printing	1.5	3.7	4.7	3.6	1.9	17.1	0.4	11.9	6.4	3.8	0.4	0.0	55.4
Chemicals	23.6	45.4	124.2	30.6	12.1	99.2	68.1	33.5	17.4	12.2	20.3	0.0	486.7
Petroleum	5.5	9.6	72.9	10.9	18.2	19.4	0.8	6.3	3.4	1.7	2.0	0.0	150.8
Plastics	14.5	10.3	8.3	6.3	3.3	29.8	1.6	12.2	8.1	3.6	0.6	0.0	98.9
Stone-clay-glass	17.2	2.6	14.0	11.1	4.7	15.9	2.6	6.0	4.1	2.4	0.2	0.0	80.8
Primary Metals	115.5	4.5	38.8	30.6	13.0	44.0	128.2	16.4	14.0	4.9	1.2	0.0	411.2
Fab Metals	17.1	3.7	7.6	5.8	10.4	19.2	4.2	10.5	8.2	2.9	0.3	0.0	89.9
Ind Machinery	8.5	4.2	8.6	6.5	18.0	23.0	3.1	33.5	18.3	7.8	0.3	0.0	131.8
Electronics	3.4	2.4	0.9	0.7	2.3	2.0	1.8	6.6	2.7	1.7	0.2	0.0	24.5
Transp Equip	16.3	9.0	8.7	6.6	14.8	14.2	4.1	27.6	17.5	6.4	1.2	0.0	126.4
Misc	1.4	1.0	0.6	0.5	1.2	2.3	0.2	4.1	2.3	1.1	0.0	0.0	14.8
WWT	0.3	0.1	16.8	8.1	0.1	0.0	0.0	0.7	1.1	0.0	0.0	0.0	27.1
Total	251.5	155.4	401.6	179.4	125.7	424.9	222.8	207.0	133.3	68.4	51.5	0.0	2,221.3

4.3 Natural Gas

4.3.1 Residential

4.3.1.1 Residential Building Types

The natural gas analysis used the same residential customer classes as the electric analysis.

The total number of residential natural gas customers was given by EIA's SEDS (2008) as 1,352,015, or 50.32% of electricity customers. These customers were disaggregated into the four customer classes using the same methodology applied to electric customers. Table 4-15 shows baseline (2008) and forecast consumption and customer counts. Table 4-16 shows number of customers by customer class.

Table 4-15
Residential Natural Gas Baseline and Forecast Figures

	Baseline	Source	Forecast 2011
Natural Gas Customers	1,352,015	SEDS 2008	1,365,701
Natural Gas Consumption (Dth)	114,600,000	SEDS 2008	105,001,999

Table 4-16
Number of Residential Customers by Class and Fuel (2011)

	SF	MF	SF-LI	MF-LI	Total
Gas	954,605	72,294	312,188	26,614	1,365,701

4.3.1.2 Residential End-use Saturations

The residential gas saturation estimates (the percentages of homes with the base measure installed) were calculated based on the 2006 "Missouri Statewide Residential Lighting and Appliance Efficiency Saturation Study" by KEMA (formerly RLW Analytics) and RECS 2005 microdata.

Table 4-17
Residential Natural Gas End-Use Saturations

	SF	MF	SF LI	MF LI	
Furnace	0.765	0.765	0.765	0.765	RLW 2006
Boiler	0.008	0.008	0.008	0.008	RLW 2006
Room Heat	0.020	0.020	0.020	0.020	RLW 2006
Water Heating	0.765	0.765	0.765	0.765	RLW 2006
Clothes Dryer	0.119	0.119	0.119	0.119	RLW 2006
Cooking	0.356	0.344	0.456	0.391	RECS microdata, Region 2
Other	0.047	0.015	0.025	0.010	RECS microdata, Region 2

4.3.1.3 Residential Energy Intensities

Residential gas end-use energy intensities were taken from RECS microdata. For weather-sensitive measures we used data from climate zone 3 in census divisions 3, 4 and 6. For non-weather sensitive measures, we used the West North Central census division.

Table 4-18
Residential Natural Gas Energy Intensity (kBtu/end-use sq ft)

EUI	SF	MF	SF LI	MF LI	
Furnace	64	61	63	75	RECS microdata, CZ 3 in Division 3, 4 & 6, calibrated
Boiler	113	56	117	63	RECS microdata, CZ 3 in Division 3, 4 & 7, calibrated
Room Heat	57	22	89	22	RECS microdata, CZ 3 in Division 3, 4 & 8
Water Heating	31	15	28	23	RECS microdata, CZ 3 in Division 3, 4 & 8
Clothes Dryer	10	10	4	4	RECS microdata, West North Central Midwest
Cooking	6	5	5	6	RECS microdata, West North Central Midwest
Other	14	14	1	1	RECS microdata, West North Central Midwest
Total (kBtu/sq ft)	79	62	75	79	

4.3.1.4 Residential Energy Use

Table 4-19 shows the number of households by building type, and energy consumption by building type and end-use. Energy use is calculated by multiplying together the saturations, EUIs, and number of households. Figure 4-13 summarizes natural gas use by end-use, and Figure 4-14 summarizes use by customer class.

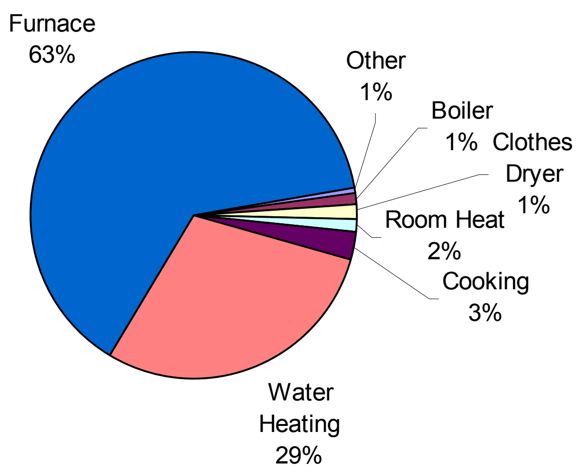
Table 4-19

Residential Natural Gas Housing Stock and Energy Us by Building Type and End-Use

	Single Family	Multifamily	Single Family Low Income	Multifamily Low Income	Total
Homes	954,605	72,294	312,188	26,614	1,339,087
Energy Consumption (Dth)					
Furnace	46,763,523	3,365,559	15,094,423	1,531,530	66,755,034
Boiler	810,546	30,471	274,277	12,582	1,127,876
Room Heat	1,063,396	31,503	541,141	11,597	1,647,637
Water Heating	22,683,594	840,943	6,612,519	477,979	30,615,036
Clothes Dryer	1,086,837	82,308	146,601	12,498	1,328,245
Cooking	2,006,944	125,108	696,707	64,328	2,893,088
Other	609,495	15,222	10,022	343	635,083
Total	75,024,336	4,491,115	23,375,690	2,110,858	105,001,999

Figure 4-13

Residential Natural Gas Use by End Use



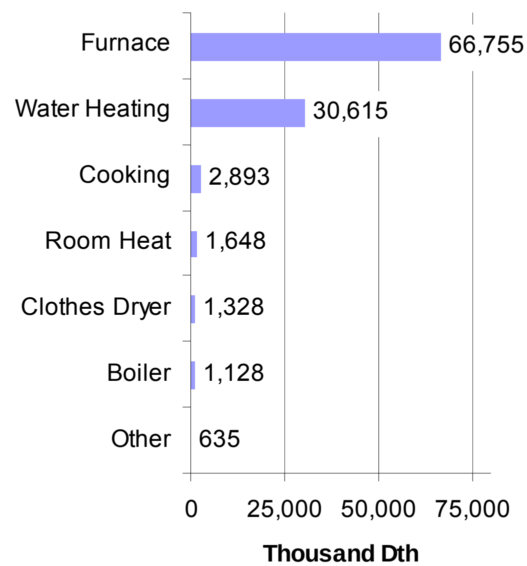
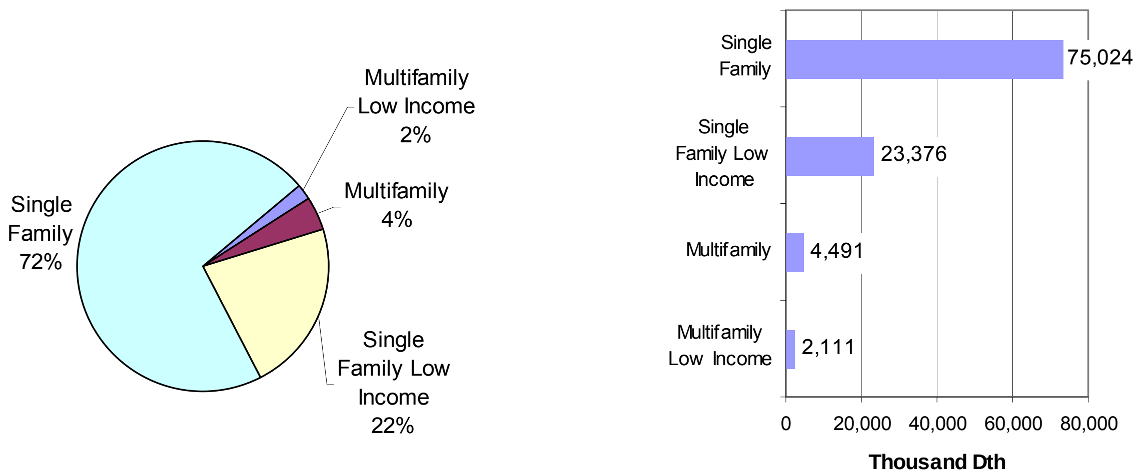


Figure 4-14
Residential Natural Gas Use by Building Type

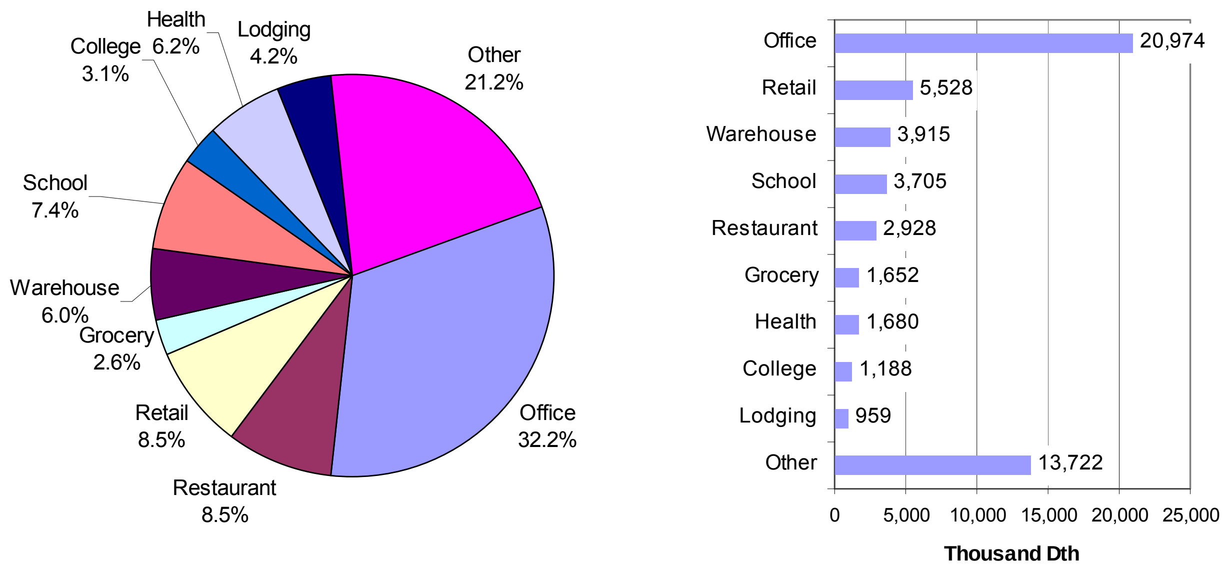


4.3.2 Commercial

4.3.2.1 Commercial Natural Gas Consumption by Building Type

Unlike the electricity sector, no gas market analyses were available through any of Missouri's gas utilities, nor did we have access to billing data. We therefore looked to other recent gas studies KEMA did for which we had access to utility billing data by NAICS (North American Industry Classification System) code. We have found the distribution of energy use across building types to be very similar across different regions. We took the energy use distribution by building type for Xcel Energy's Colorado service territory and for the state of Connecticut and reweighted them to reflect the distribution of floorspace by building type in Missouri (for example, if offices represented 36 percent of Xcel's floorspace compared to 24 percent of Missouri floorspace, we scaled back Xcel's office energy use by a third before calculating the distribution of energy use). The distributions for Xcel and Connecticut were averaged and applied to Missouri commercial natural gas use, developed as discussed above. The following chart shows commercial natural gas use by building type.

Figure 4-15
Commercial Natural Gas Use by Building Type



4.3.2.2 Commercial End-use Saturations

We relied on the U.S. DOE Commercial Building Energy Consumption Survey (CBECS) for end use saturation estimates of natural gas equipment.

Table 4-20
Commercial Natural Gas Saturations

End Use	Office	Restaurant	Retail	Grocery	Warehouse	School	College	Health	Lodging	Other
Heating	71%	74%	74%	98%	88%	79%	89%	83%	39%	82%
Water Heating - high standby applications	51%	79%	57%	75%	55%	77%	85%	80%	94%	69%
Water Heating - low standby applications	51%	79%	57%	75%	55%	77%	85%	80%	94%	69%
Cooking - Fryer	21%	88%	0%	66%	0%	48%	0%	34%	36%	6%
Cooking - Steamer	0%	17%	0%	33%	0%	69%	0%	80%	36%	1%
Cooking - Convection Oven	31%	31%	28%	33%	0%	69%	0%	80%	36%	16%
Cooking - Griddle	21%	73%	0%	0%	0%	42%	0%	34%	36%	8%
Cooking - Range	23%	87%	0%	0%	0%	2%	0%	67%	36%	29%
Other	0%	6%	0%	0%	11%	6%	10%	10%	6%	1%

4.3.2.3 Commercial Energy Intensity

We began with California Commercial End-Use Survey data as a starting point for natural gas EUI estimates. These values were adjusted to account for Missouri’s climate differences.

Table 4-21
Commercial Natural Gas EUIs (kBtu/end use sq ft)

End Use	Office	Restaurant	Retail	Grocery	Warehouse	School	College	Health	Lodging	Other
Heating	63.4	15.3	29.1	28.7	18.9	33.7	15.1	15.0	35.9	21.6
Water Heating - high standby applications	9.0	22.5	4.8	20.9	2.1	0.0	0.0	0.0	0.0	33.0
Water Heating - low standby applications	0.0	28.3	0.0	0.0	0.0	10.2	11.8	24.6	28.8	0.0
Cooking - Fryer	0.60	69.34	3.30	8.14	2.81	0.62	1.37	1.55	3.40	1.50
Cooking - Steamer	0.35	40.46	1.93	4.75	1.64	0.36	0.80	0.90	1.98	0.87
Cooking - Convection Oven	0.09	10.46	0.50	1.23	0.42	0.09	0.21	0.23	0.51	0.23
Cooking - Griddle	0.24	27.63	1.31	3.24	1.12	0.25	0.55	0.62	1.35	0.60
Cooking - Range	0.30	35.18	1.67	4.13	1.43	0.32	0.69	0.79	1.72	0.76
Other	27.8	43.8	12.2	10.0	11.3	3.7	11.1	21.2	3.9	75.4

4.3.2.4 Commercial Floor space

As discussed in the electricity baseline section, we have typically found floorspace data to be the least reliable of the inputs to the ASSYST baseline analysis. However, unlike the electricity analysis, there was too much uncertainty in EUIs to use floorspace as a calibration factor. We therefore used the floorspace determined for the electric analysis as a starting point, and scaled it back 10 percent to account for electric-only customers. With floorspace estimated in this manner, we were then able to calibrate the weather-sensitive EUIs so that overall energy use balanced with our sector totals.

Floorspace is shown with energy consumption in the tables below.

4.3.2.5 Commercial Energy Consumption

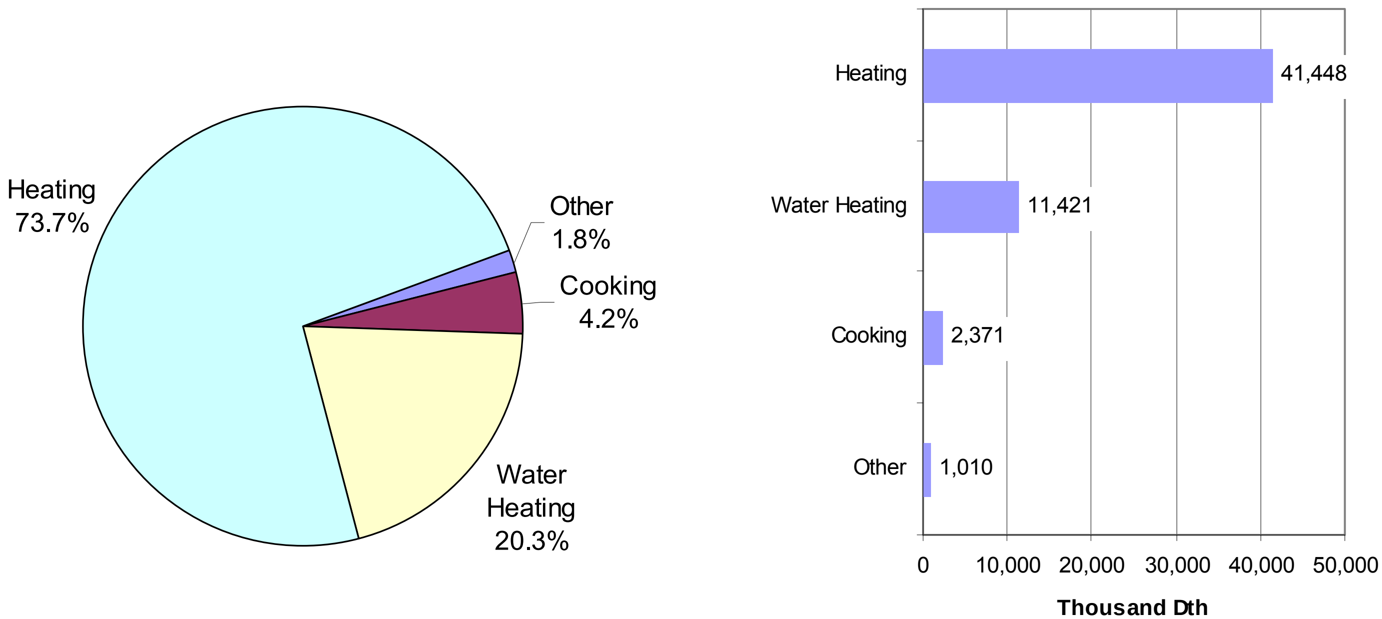
The following tables and figures show commercial floorspace by building type and energy consumption by end-use and building type for natural gas.

Table 4-22

Commercial Natural Gas Floorspace (thousand sq ft) and Energy Consumption (Dekatherms) by Building Type and End Use

	Office	Restaurant	Retail	Grocery	Warehouse	School	College	Health	Lodging	Other	Total
Floorspace (thous. sq ft)	421,450	31,737	230,039	33,896	207,071	136,517	82,021	112,671	62,489	329,860	1,647,751
Energy Consumption											
Heating	189,879,320	3,546,909	49,004,906	9,463,546	34,280,978	36,327,127	10,933,942	13,867,551	8,693,987	58,479,258	414,477,523
Water Heating - high standby applications	19,331,667	5,614,685	6,271,474	5,252,408	2,328,813	0	0	0	0	75,412,822	114,211,868
Water Heating - low standby applications	0	7,047,277	0	0	0	10,724,167	8,196,639	22,105,305	16,914,973	0	64,988,361
Cooking – Fryer	524,248	19,315,785	0	1,800,704	0	409,039	0	588,300	759,234	314,829	23,712,137
Cooking - Steamer	0	2,107,599	0	525,357	0	339,582	0	805,909	443,006	15,916	4,237,369
Cooking - Convection Oven	116,149	1,037,268	315,990	135,793	0	88,387	0	208,309	114,507	119,577	2,135,980
Cooking - Griddle	208,890	6,395,314	0	0	0	141,377	0	234,411	302,521	149,874	7,432,387
Cooking - Range	294,450	9,702,547	0	0	0	6,468	0	591,326	385,213	727,337	11,707,342
Other	0	801,162	0	0	2,539,825	313,296	943,080	2,348,787	139,050	3,011,834	10,097,034
Total	210,354,725	55,568,544	55,592,370	17,177,807	39,149,616	48,349,443	20,073,661	40,749,898	27,752,490	138,231,446	653,000,000

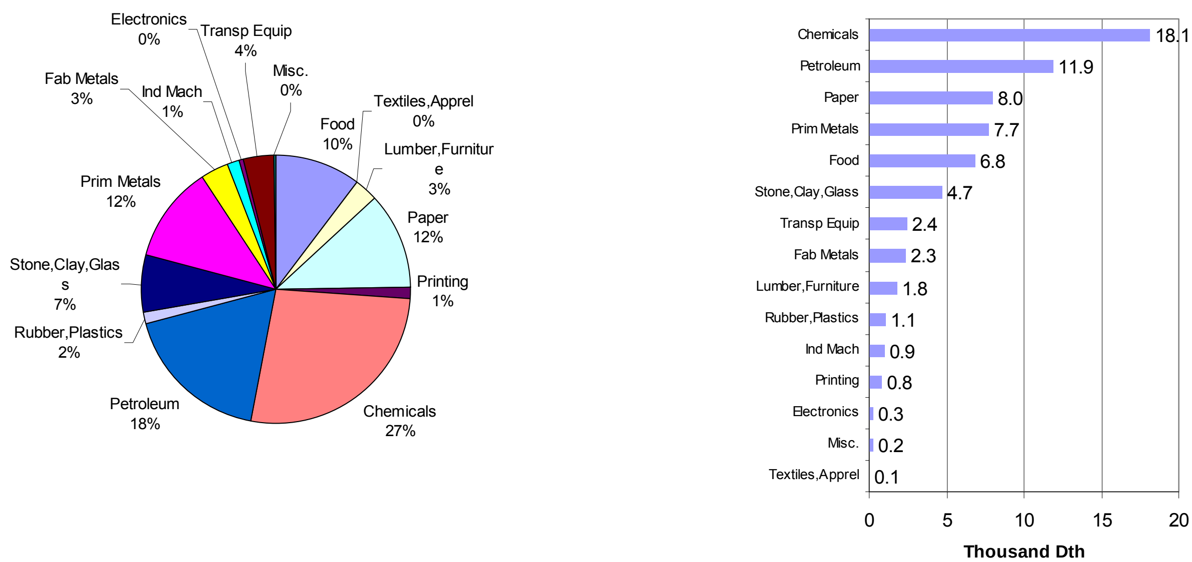
Figure 4-16
Commercial Natural Gas Consumption by End Use



4.3.3 Industrial

The distribution of industries varies greatly by region, making it impossible to apply distributions from other studies as we did with commercial gas. We adopted an approach based on employment data by industry. The Bureau of the Census' 2007 Economic Census provides state-level employment by NAICS code, which we combined with energy use per employee by industry from the Department of Energy's Manufacturing Energy Consumption Survey to estimate distributions natural gas use by industry for Missouri. These were then normalized to the consumption estimates developed above. The following figures show the breakdown of natural gas by industry.

Figure 4-17
Industrial Sector Natural Gas Use by Industry



4.3.3.1 Industrial Sector End Use Consumption

Energy use was disaggregated into end-use consumption percentages based mainly on the Department of Energy's Manufacturing Energy Consumption Survey (MECS). Where possible, the most current end-use by industry splits were used. A minority of end use splits were withheld in the 2006 version due to sampling errors, and were informed by applying ratios derived from 2002 MECS end-use data.

Table 4-23
Industrial Natural Gas End-Use Shares

Industry	Proc Heat	HVAC	Conventional Boiler Use	CHP and/or Cogen	Other	Total
Food	0.31	0.05	0.52	0.04	0.07	1.00
Textiles,Apparel	0.30	0.06	0.35	0.12	0.17	1.00
Lumber,Furniture	0.53	0.13	0.16	0.00	0.18	1.00
Paper	0.26	0.03	0.25	0.33	0.13	1.00
Printing	0.66	0.18	0.13	0.00	0.03	1.00
Chemicals	0.28	0.02	0.28	0.32	0.11	1.00
Petroleum	0.59	0.01	0.14	0.19	0.07	1.00
Rubber,Plastics	0.25	0.19	0.45	0.00	0.10	1.00
Stone,Clay,Glass	0.78	0.04	0.04	0.00	0.14	1.00
Prim Metals	0.78	0.07	0.05	0.05	0.05	1.00
Fab Metals	0.64	0.15	0.15	0.01	0.06	1.00
Ind Mach	0.29	0.37	0.20	0.05	0.10	1.00
Electronics	0.30	0.29	0.31	0.00	0.10	1.00
Transp Equip	0.30	0.34	0.15	0.02	0.19	1.00
Misc.	0.24	0.48	0.16	0.00	0.12	1.00

Source: DOE 2002 and 2006 MECS

Figure 4-18
Industrial Natural Gas Consumption by End Use

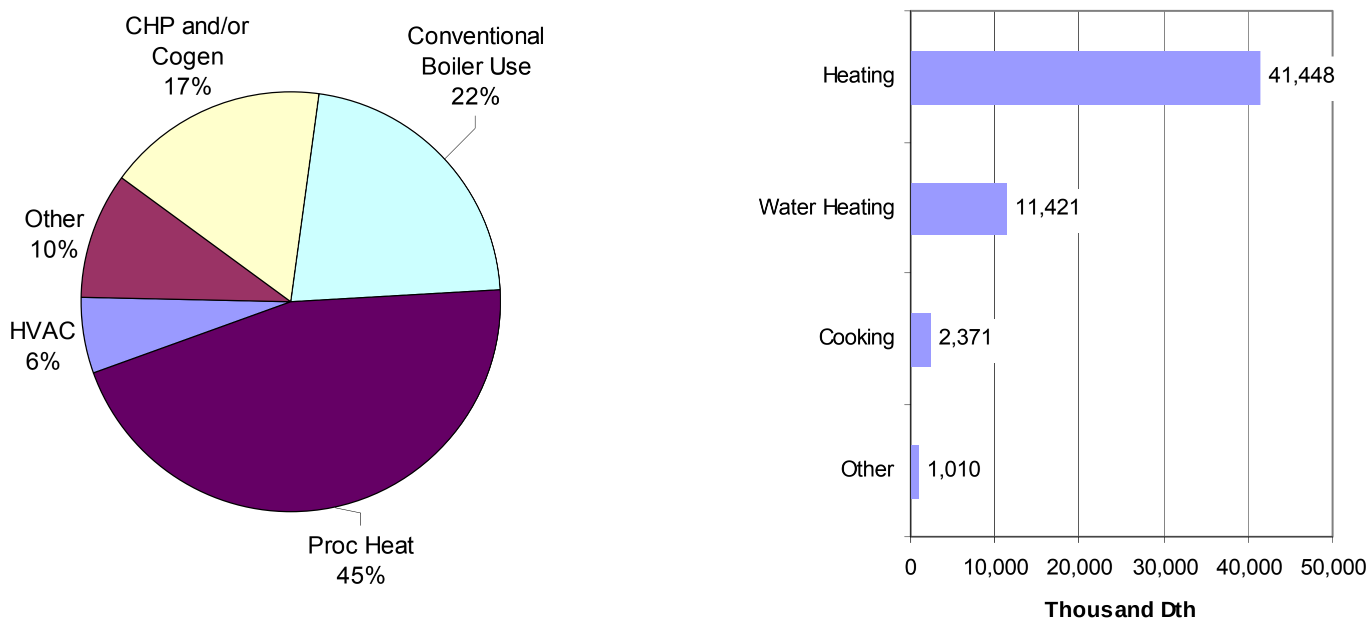


Table 4-24
Industrial Natural Gas Consumption by Industry and End Use (thousand Therms)

Industry	Proc Heat	HVAC	Conventional Boiler Use	CHP and/or Cogen	Other	Total
Food	21,490	3,426	35,817	3,011	4,568	68,312
Textiles, Apparel	229	43	264	93	125	754
Lumber, Furniture	9,635	2,363	2,909	73	3,200	18,180
Paper	20,701	2,243	20,184	26,394	10,006	79,528
Printing	5,182	1,451	1,036	0	207	7,877
Chemicals	50,342	2,938	49,808	57,286	20,564	180,939
Petroleum	70,614	1,009	16,717	22,481	8,070	118,891
Rubber, Plastics	2,656	2,056	4,798	17	1,097	10,623
Stone, Clay, Glass	36,568	1,792	2,108	105	6,428	47,001
Prim Metals	60,460	5,027	3,940	3,668	4,076	77,172
Fab Metals	14,911	3,380	3,380	199	1,392	23,261
Ind Mach	2,745	3,431	1,830	458	915	9,379
Electronics	764	733	794	6	269	2,567
Transp Equip	7,363	8,372	3,631	403	4,640	24,409
Misc.	500	1,000	333	0	250	2,084
Total	304,162	39,264	147,550	114,194	65,806	670,976

5. Electric Energy-Efficiency Potential Results

In this section, we present estimates of electric energy-efficiency potential. First, we present technical and economic potential results for all electric measures considered in the study. Next, we present estimates of achievable program potential under three different scenarios.

5.1 Technical and Economic Potential

Estimates of overall energy-efficiency technical and economic potential are discussed in section 5.1.1. More detail on these potentials is presented in section 5.1.2. Section 5.1.3 presents the results of high and low avoided cost scenarios. Energy-efficiency supply curves are shown in section 5.1.4.

5.1.1 Overall Technical and Economic Potential

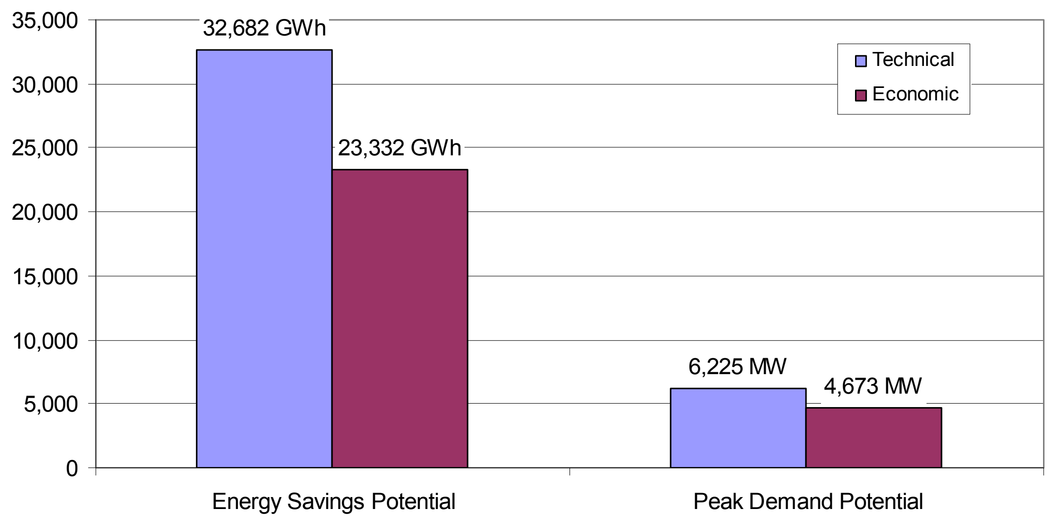
Error! Reference source not found. presents our overall estimates of total technical and economic potential for electrical energy and peak-demand savings for Missouri. Technical potential represents the sum of all savings from all of the measures deemed applicable and technically feasible. Economic potential is based on efficiency measures that are cost-effective, as determined by the total resource cost (TRC) test—a benefit-cost test that compares the value of avoided energy production and power-plant construction to the costs of energy-efficiency measures and program activities necessary to deliver them. The values of both energy savings and peak-demand reductions are incorporated in the TRC test.

- Energy Savings. Technical potential is estimated at about 32,682 GWh per year, and economic potential at 23,332 GWh per year by 2020 (about 35 and 25 percent of base 2020 usage, respectively).

- Peak-Demand Savings. Technical potential is estimated at about 6,225 MW, and economic potential at 4,673 MW by 2020 (about 36 and 27 percent of base 2020 demand, respectively).

Note that the technical and economic potentials include the effect of CFLs, although federal lighting standards may preempt much of the CFL potential that might otherwise be achieved through programs.

5-1 Estimated Electric Technical and Economic Potential 2020



5.1.2 Technical and Economic Potential Detail

In this subsection, we explore technical and economic potential in more detail, looking at potentials by sector and by end use.

5.1.2.1 Potentials by Sector

Figure 5-2 and Figure 5-3 show estimates of technical and economic energy (GWh) and demand (MW) savings potential by sector.

Figure 5-3 shows how the three sectors contribute to base energy use and peak demand, technical energy and demand savings, and economic energy and demand savings. On the energy side, the residential sector contribution to potential is greater than its contribution to base energy use, while industrial contributes less to potential, and commercial is roughly proportional. On the peak demand side, residential similarly contributes more to potential than to base use, with both commercial and industrial contributing less to potential than to base use.

Figure 5-2
Technical and Economic Potential (2020)
Energy Savings by Sector—GWh per Year

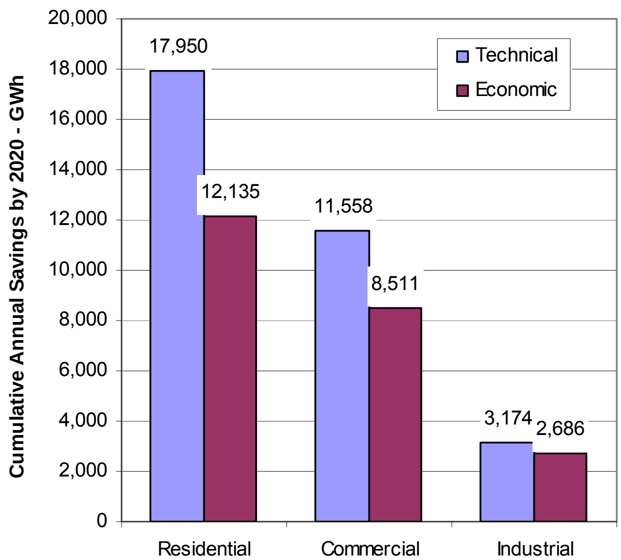


Figure 5-3
Technical and Economic Potential (2020)
Demand Savings by Sector—MW

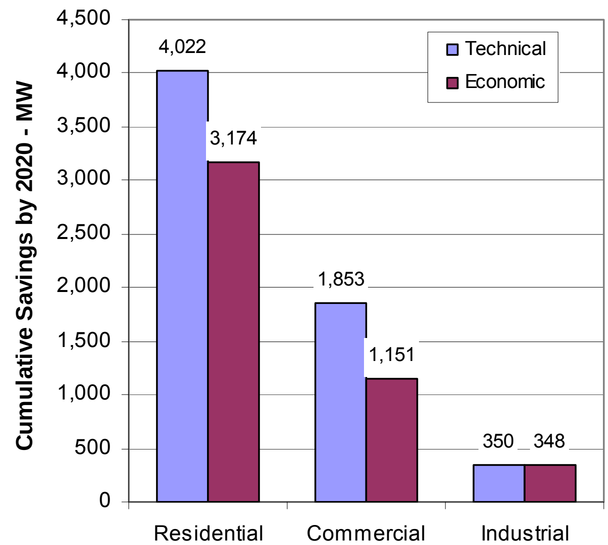


Figure 5-4
Shares of Base Energy Use and Peak Demand, Technical and Economic Energy and Peak Demand Potential by Sector

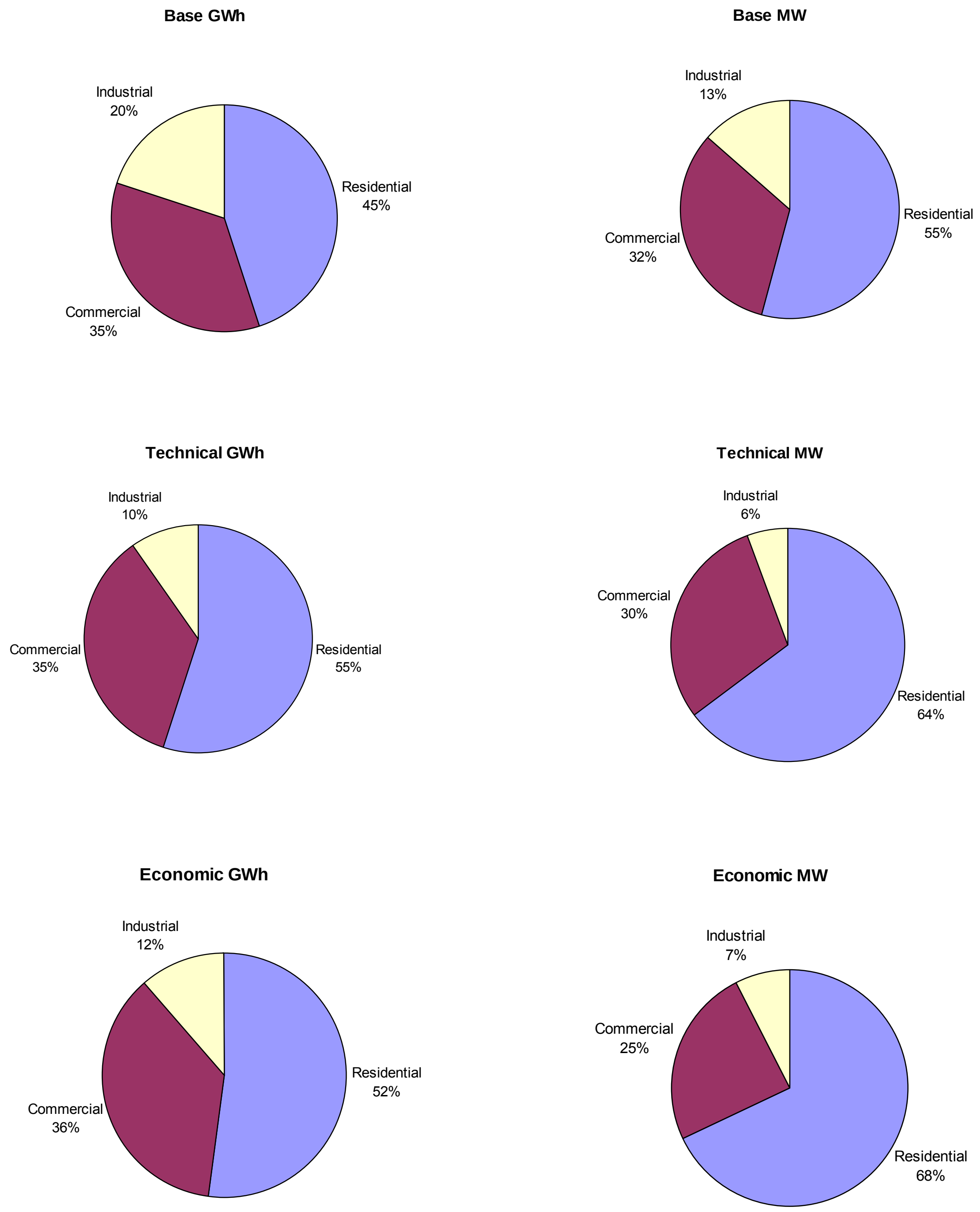


Figure 5-5 and Figure 5-6 show the same potentials as a percentage of 2020 base energy and base peak demand. The residential sector has the highest energy savings potential in relation to base energy use, followed by the commercial sector. The estimated savings fraction is lowest for the industrial sector at around 17 percent for technical and 14 percent for economic savings. A similar pattern holds for peak demand.

Figure 5-5
Technical and Economic Potential (2020)
Percentage of Base Energy Use

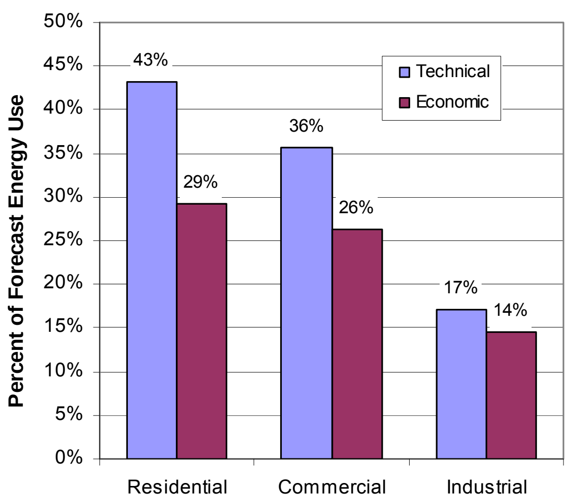
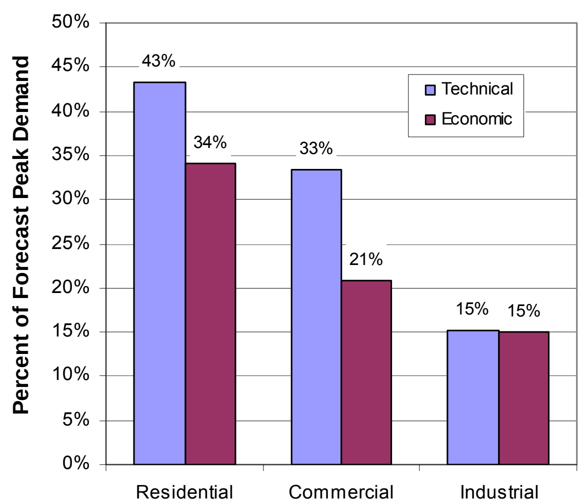


Figure 5-6
Technical and Economic Potential (2020)
Percentage of Base Peak Demand



5.1.2.2 Potentials by Building Type

Figure 5-7 and Figure 5-8 show the potentials in the residential sector by building type. Single-family homes account for about 85 percent of the potential, and low-income homes account for about 24 percent of the potential.

Figure 5-7
Residential Energy-Savings Potential by Building Type (2020)

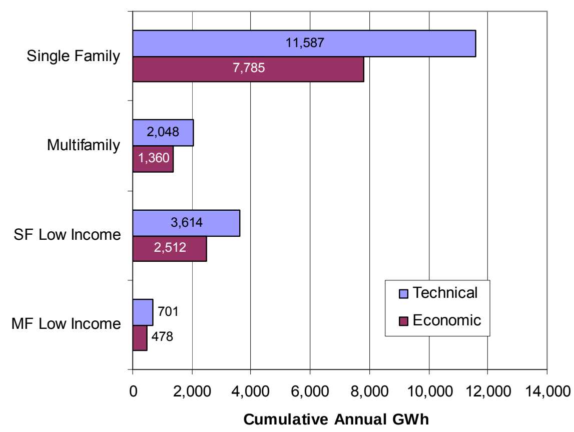


Figure 5-8
Residential Demand-Savings Potential by Building Type (2020)

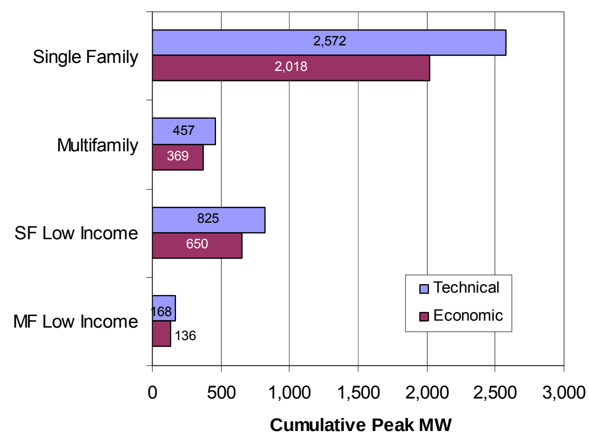


Figure 5-9 and Figure 5-10 show the building-type breakdown of commercial potential. Offices account for about 36 percent of the economic energy potential, followed by grocery, retail, and miscellaneous commercial buildings.

Figure 5-9
Commercial Economic Energy-Savings Potential by Building Type (2010)

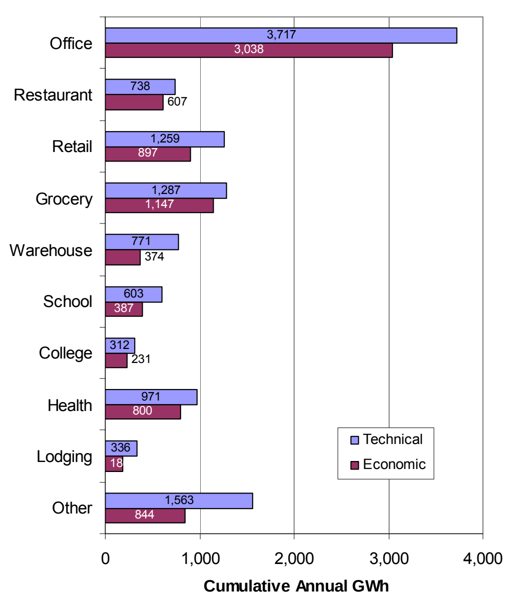


Figure 5-10
Commercial Economic Demand-Savings Potential by Building Type (2010)

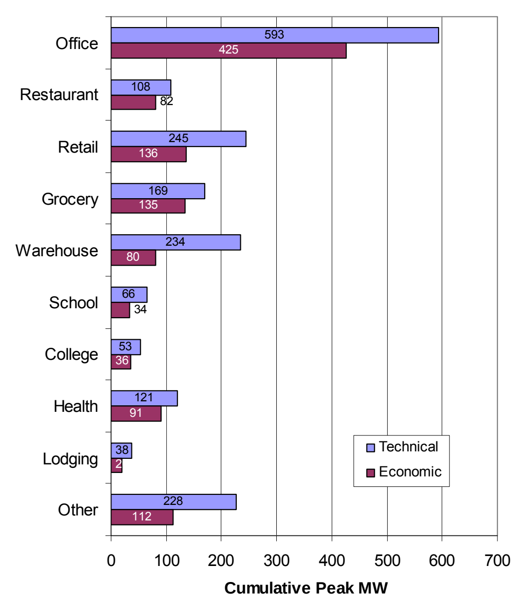


Figure 5-11 and Figure 5-12 show the business-type breakdown of industrial potential. Key industries in terms of economic potential include chemicals, paper, food processing, and primary metals.

Figure 5-11
Industrial Economic Energy-Savings Potential by Business Type (2020)

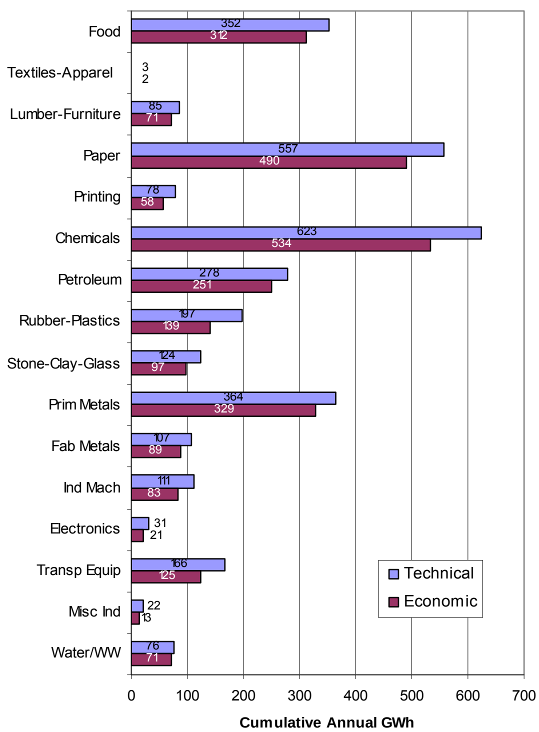
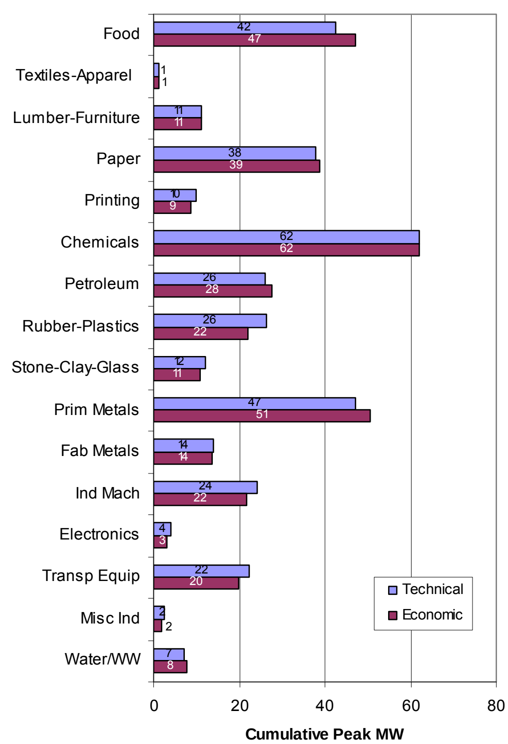


Figure 5-12
Industrial Economic Demand-Savings Potential by Business Type (2020)



5.1.2.3 Potentials by End Use

Figure 5-13 and Figure 5-14 show the end-use breakdown of technical and economic potential in the residential sector. Energy economic potential is split fairly evenly among the lighting and cooling end uses, followed by space heating and furnace fans. Water heating ranks high in technical, but not in economic energy potential. Cooling accounts for most of the peak-demand savings potential, since very little lighting is used on warm summer afternoons.

Figure 5-13
Residential Economic Energy-Savings Potential by End Use (2020)

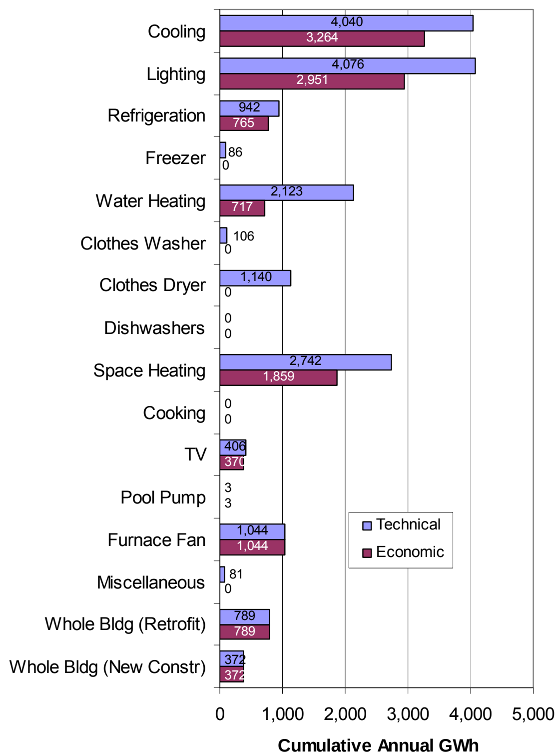


Figure 5-14
Residential Economic Demand-Savings Potential by End Use (2020)

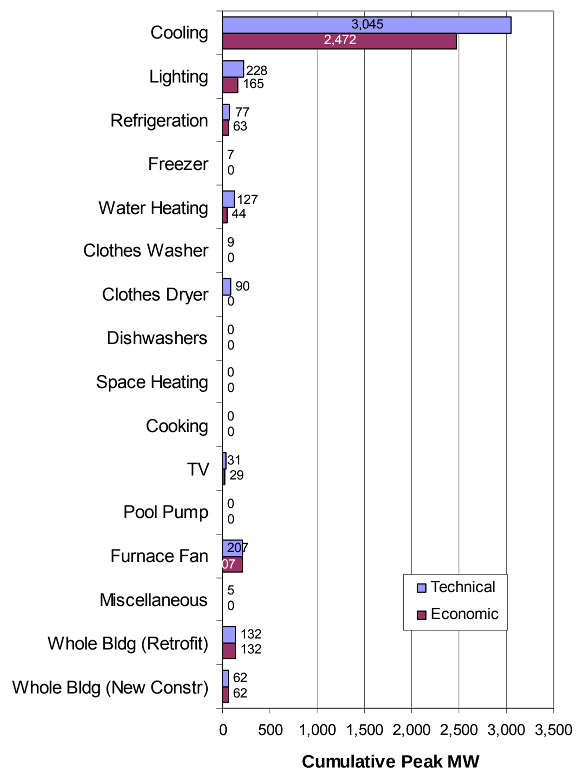


Figure 5-15 and Figure 5-16 show the end-use breakdown of commercial potential. Energy savings potential is highest for indoor lighting. In technical potential, lighting is followed by cooling and whole buildings (new construction). For economic potential, lighting is followed by whole buildings, then cooling. Cooling accounts for most of the peak-demand savings potential, followed by indoor lighting.

Figure 5-15
Commercial Economic Energy Savings Potential by End Use (2014)

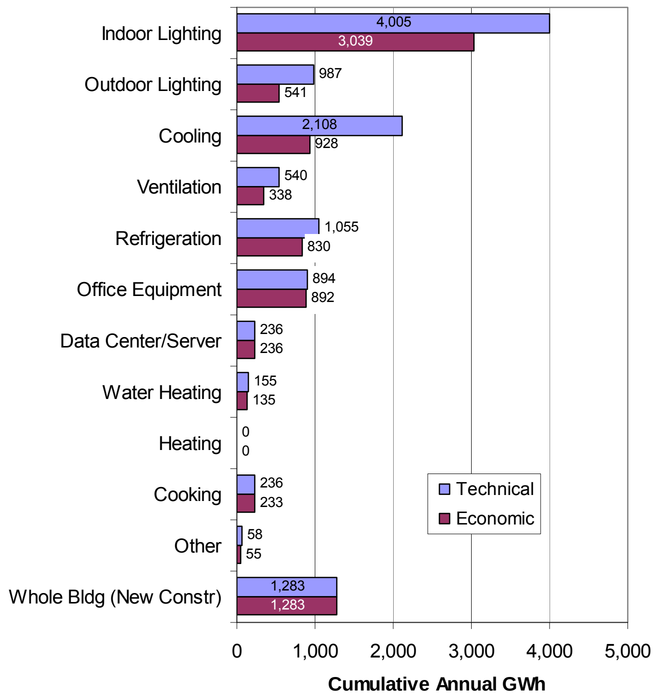


Figure 5-16
Commercial Economic Demand Savings Potential by End Use (2014)

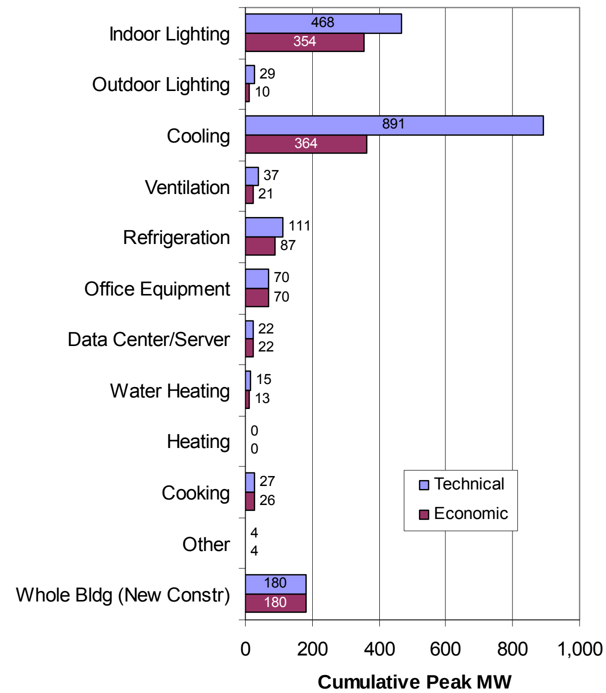


Figure 5-17 and Figure 5-18 show the end-use breakdown of industrial potential. Pumping-system measures provide the largest source of economic potential, followed by fans, drives, and compressed air.

Figure 5-17
Industrial Economic Energy-Savings Potential by End Use (2020)

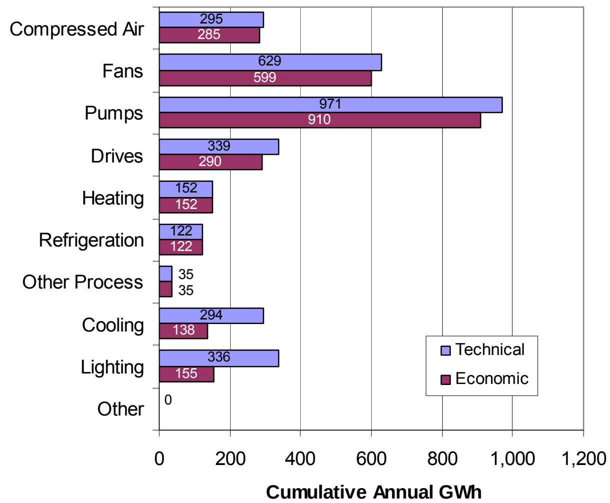
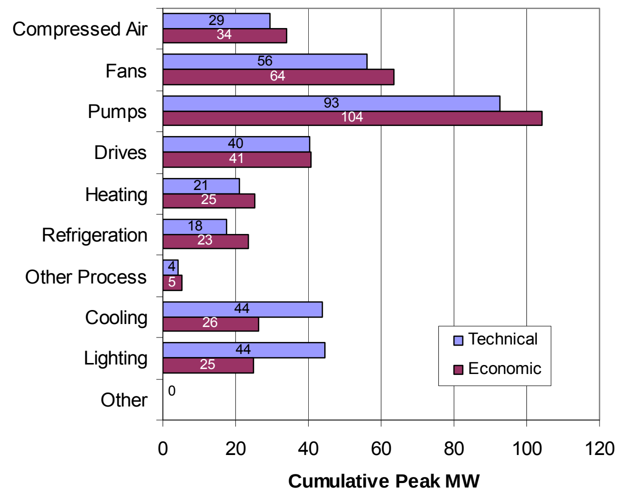


Figure 5-18
Industrial Economic Demand-Savings Potential by End Use (2020)



5.1.3 Avoided Cost Scenarios

We examined two alternative avoided cost scenarios in addition to the base scenario. For the low avoided cost scenario, we reduced avoided costs by 20 percent in each year of the forecast. For the high scenario, we increased costs by 50 percent. Figure 5-19 shows technical and economic potential for the three scenarios (technical potential is the same for all three scenarios). In Table 5-1, we compare the three scenarios in terms of percent of sales, percent of technical, and relative to the economic potential of the base avoided cost scenario. The low avoided cost scenario results in economic savings that are 5 percent lower for energy and 4 percent lower for peak demand compared to the base avoided cost scenario. The high avoided cost scenario results in savings that are 6 percent higher for energy and 3 percent higher for peak demand.

Figure 5-19
Estimated Electricity Technical and Economic Potential for Alternative Avoided Cost Scenarios, 2020

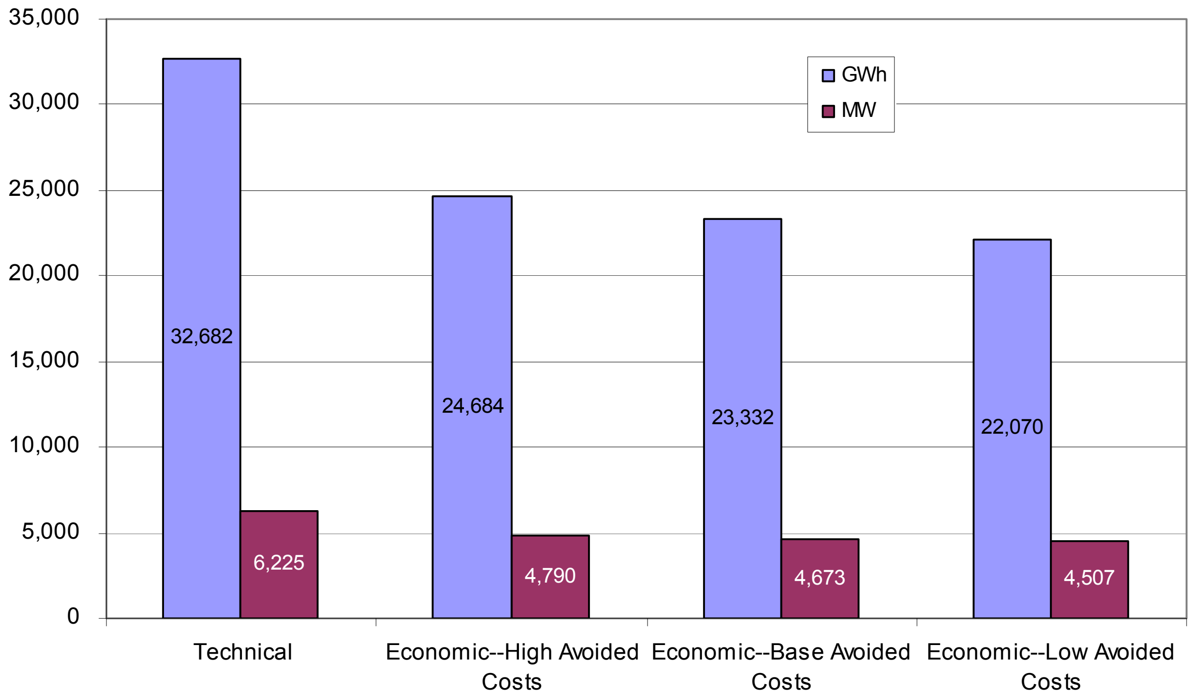


Table 5-1
Comparison of Estimated Electricity Technical and Economic Potential for Alternative Avoided Cost Scenarios, 2020

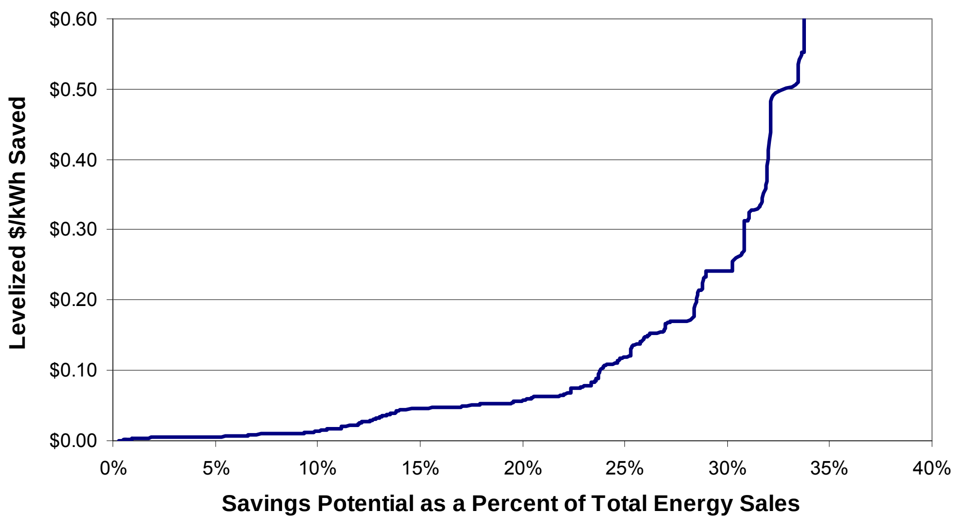
	Base	Technical	Economic--High Avoided Costs	Economic--Base Avoided Costs	Economic--Low Avoided Costs
Energy					
GWh	92,556	32,682	24,684	23,332	22,070
% of consumption		35%	27%	25%	24%
% of Technical			76%	71%	68%
% of Economic--Base Avoided Costs			106%	100%	95%
Peak Demand					
MW	17,139	6,225	4,790	4,673	4,507
% of consumption		36%	28%	27%	26%
% of Technical			77%	75%	72%
% of Economic--Base Avoided Costs			103%	100%	96%

5.1.4 Energy-Efficiency Supply Curves

A common way to illustrate the amount of energy savings per dollar spent is to construct an energy-efficiency supply curve. A supply curve typically is depicted on two axes: one captures the cost per unit of saved energy (e.g., levelized $/kWh saved), and the other shows energy savings at each level of cost. Measures are sorted on a least-cost basis, and total savings are calculated incrementally with respect to measures that precede them. The costs of the measures are levelized over the life of the savings achieved.

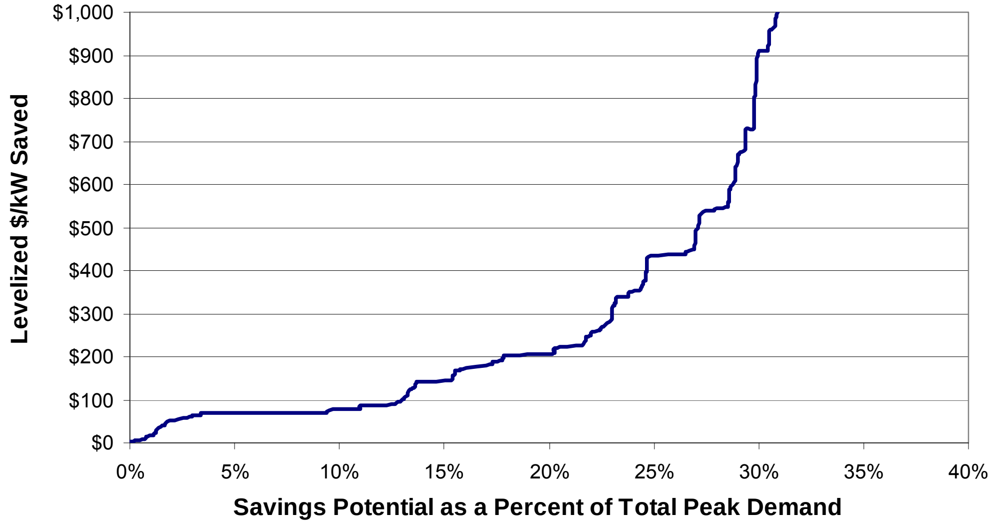
Figure 5-20 and Figure 5-21 present the supply curves constructed for this study for electric energy-efficiency and peak-demand efficiency, respectively. Each curve represents savings as a percentage of total energy or peak demand. These curves show that energy savings of about 17 percent are available at under $0.05 per kWh, and peak demand savings of about 13 percent are available at under $100 per MW. Savings potentials and levelized costs for the individual measures that comprise the supply curves are provided in Appendix G.

Figure 5-20
Electric Energy Supply Curve*



*Levelized cost per kWh saved is calculated using a 7.8 percent nominal discount rate.

Figure 5-21
Peak-Demand Supply Curve*



*Levelized cost per kW saved is calculated using a 7.8 percent nominal discount rate.

5.2 Achievable (Program) Potential

In contrast to technical and economic potential estimates, achievable potential estimates take into account market and other factors that affect the adoption of efficiency measures. Our method of estimating measure adoption takes into account market barriers and reflects actual consumer- and business-implicit discount rates. This section presents results for achievable potential for the scenarios described in section 3.3 Scenario Analysis, first at the summary level and then by sector. More detail on achievable program potential will be forthcoming in Appendix H.

5.2.1 Markets within the scenarios

For each electric scenario we modeled achievable potential by market. We used the following markets:

Table 5-2 Market Definitions

Customer Sector	Building type	Market	Measures
Residential	Existing	Replace on Burnout	All except CFLs
Residential	Existing	Retrofit	All except CFLs
Residential	Existing	Retrofit	CFLs –Until 2014
Residential	New	New Construction	All
Commercial	Existing	Replace on Burnout	All except CFLs
Commercial	Existing	Retrofit	All except CFLs
Commercial	Existing	Retrofit	CFLs- Until 2014
Commercial	New	New Construction	All
Industrial	Existing	Replace on Burnout	All
Industrial	Existing	Retrofit	All

Each the sum of the achievable potential for each scenario is built up from the potential for each of these markets.

5.2.2 Overall results

Figure 5-22 and Figure 5-23 show our estimates of achievable potential savings over time. As shown in Figure 5-22, by 2020, cumulative *net*[3] energy savings are projected to be 3,281 GWh under the three year payback scenario, 6.571 GWh under the one year payback scenario, and 7,561 GWh under the 75% incentive scenario. Figure 5-23 depicts projected net peak-demand savings under the same scenarios, 779 MW, 1,863 MW, and 1,801 MW respectively.

[3] Throughout this section, *net* refers to savings beyond those estimated to be naturally occurring; that is, from customer adoptions that would occur in the absence of any programs or standards.

Figure 5-22
Achievable Electric Energy-Savings: All Sectors

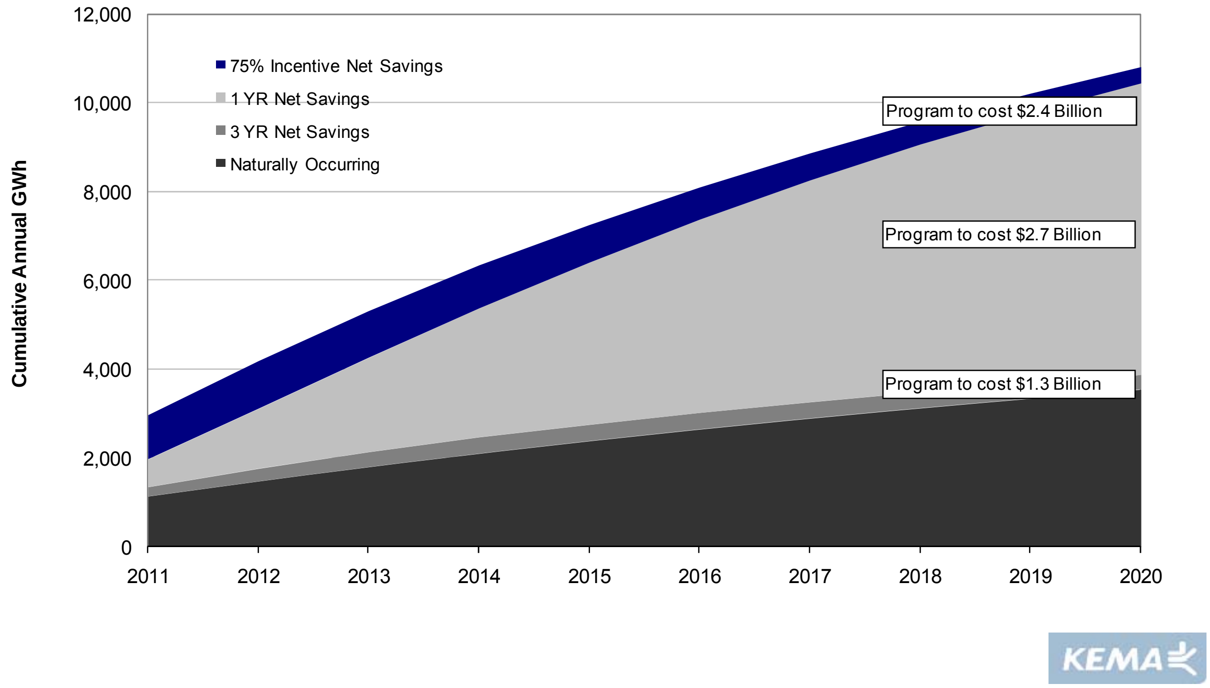


Figure 5-23
Achievable Peak-Demand Savings: All Sectors- update

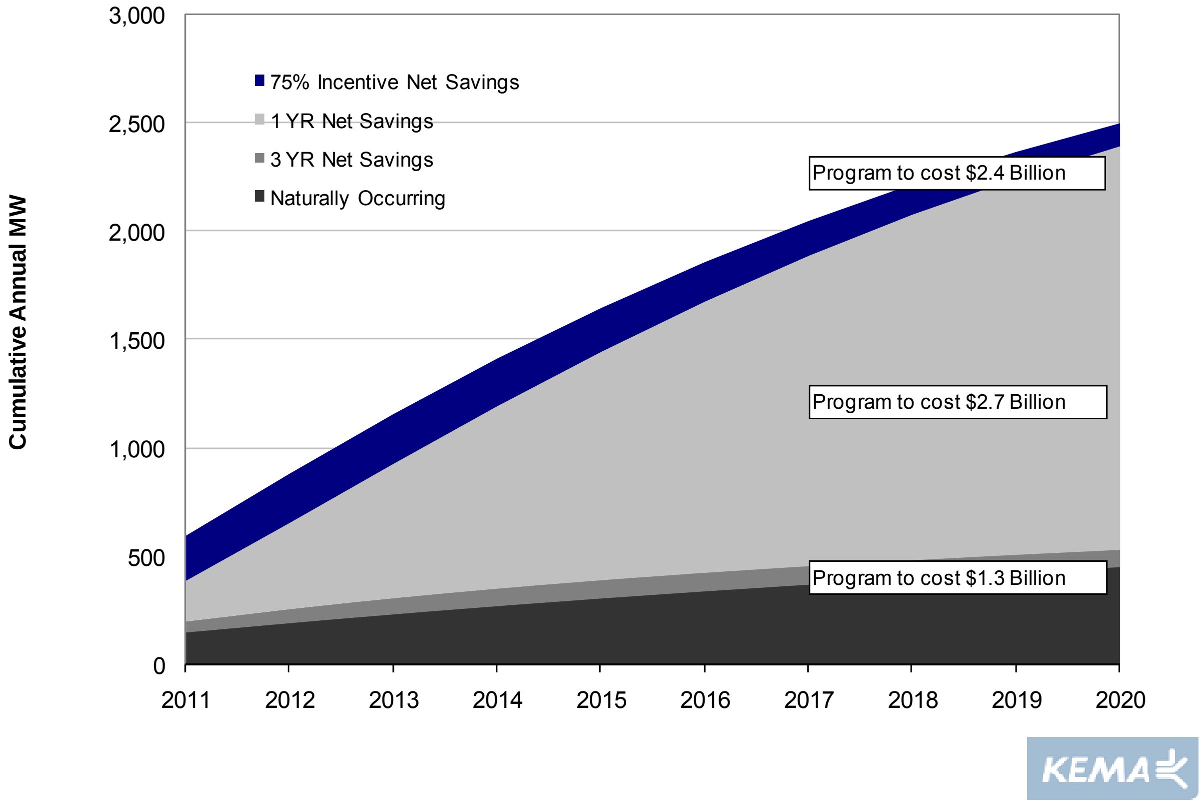
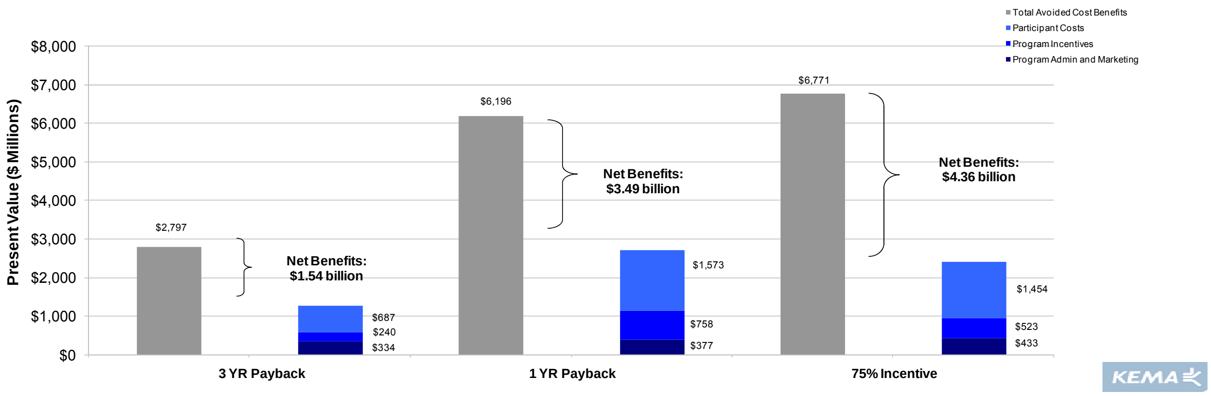


Figure 5-24 depicts costs and benefits under each funding scenario from 2010 to 2020, which are also shown in Table 5-3. The bottom line is that the net present value, the present value of all the benefits less the present value of all the costs, developed by the three year payback incentive scenario is $1.5 million, the one year payback scenario develops $3.5 million, and the 75% incentive scenario delivers $4.4 million.

Figure 5-24

Benefits and Costs of Energy-Efficiency Savings—2010-2020*



* Present value of benefits and costs over normalized 20-year measure lives; nominal discount rate is 7.9 percent, inflation rate is 1.5 percent.

All three of the funding scenarios are cost-effective based on the TRC test, which is the test used in this study to determine program cost-effectiveness. The TRC benefit-cost ratios are 2.22 for the three year payback scenario, 2.29 for the one year payback scenario, and 2.81 for the 75 percent incentive scenario. That program cost-effectiveness increases with increasing program effort indicates that program effort under all three scenarios has not reach the point of diminishing returns. Key results of our efficiency scenario forecasts from 2010 to 2020 are summarized in Table 5-3 .

Table 5-3
Summary of All Scenarios

Result - Programs	3 YR Payback	1 YR Payback	75% Incentive
Gross Energy Savings - GWh	6,406	9,696	10,185
Gross Peak Demand Savings - MW	1,175	2,259	2,169
Net Energy Savings - GWh	3,281	6,571	7,561
Net Peak Demand Savings - MW	779	1,863	1,801
Program Costs - Real, $ Million			
Administration	$193	$246	$317
Marketing	$223	$223	$221
Incentives	$597	$2,148	$1,723
Total	$1,013	$2,617	$2,260
PV Avoided Costs	$2,797	$6,196	$6,771
PV Annual Program Costs (Adm/Mkt)	$334	$377	$433
PV Net Measure Costs	$927	$2,331	$1,977
Net Benefits	$1,536	$3,488	$4,361
TRC Ratio	2.22	2.29	2.81

5.2.3 Summary of the 75 % incentive Scenario

This section presents a summary of the 75 % Incentive Scenario.

Table 5-4 presents a summary of this scenario in a tabular format for years 2011- 2020 including spending by sector, savings in MW and Gwh, spending by type and overall avoided cost benefits. The overall benefit cost ratio for this scenario is 2.81. This scenario is the most cost effective of the electric scenarios.

Table 5-4
Summary Table for the Electric 75% Incentives Scenario

Result - Programs	Program Scenario: 2011 - 2020			
	Residential	Commercial	Industrial	All Programs
Gross Energy Savings - GWh	4,969	3,471	1,745	10,185
Gross Peak Demand Savings - MW	1,520	480	170	2,169
Net Energy Savings - GWh	3962	2328	1,272	7,561
Net Peak Demand Savings - MW	1338	338	125	1,801
Program Costs - Real, $ Million				
Administration	$196,045,734	$53,413,851	$67,198,307	$316,657,892
Marketing	$65,522,074	$100,300,000	$55,413,542	$221,235,616
Incentives	$945,968,901	$559,601,124	$217,032,139	$1,722,602,164
Total	$1,207,536,709	$713,314,976	$339,643,988	$2,260,495,673
PV Avoided Costs	$4,165,622,137	$1,754,025,981	$851,680,303	$6,771,328,421
PV Annual Program Costs (Adm/Mkt)	$209,523,856	$124,195,918	$99,260,721	$432,980,494
PV Net Measure Costs	$1,097,178,519	$613,353,484	$266,565,489	$1,977,097,492
Net Benefits	$2,858,919,762	$1,016,476,580	$485,854,093	$4,361,250,435
TRC Ratio	3.19	2.38	2.33	2.81

Figure 5-25 below presents the net energy savings and savings from free riders. Figure 5-26 presents the equivalent information for demand.

Figure 5-25
Energy Savings by Sector 75 % Incentive Case

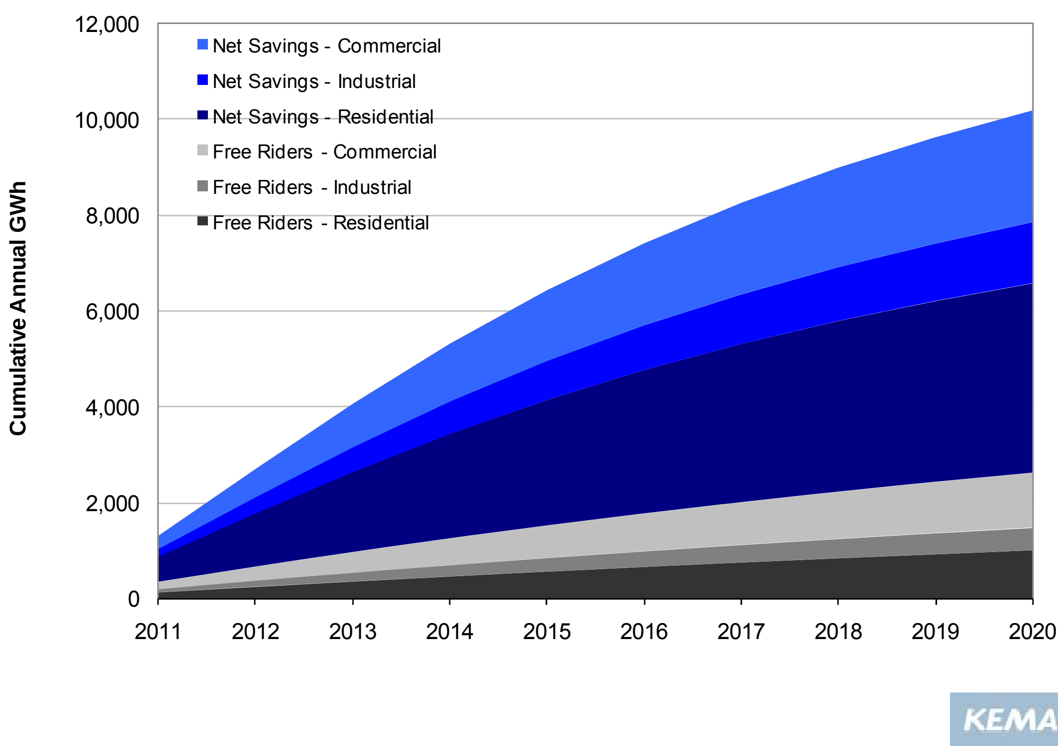


Figure 5-26
Demand Savings by Sector – 75 % incentive case

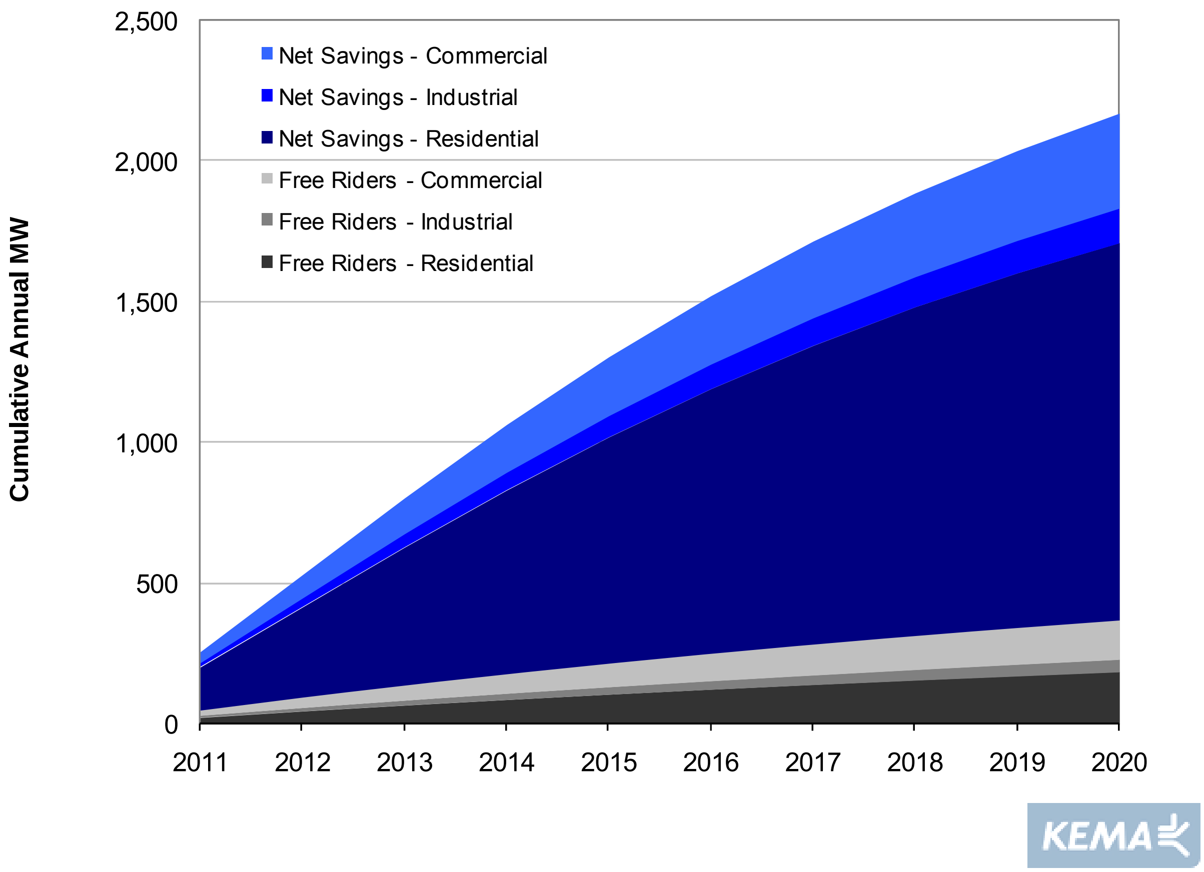
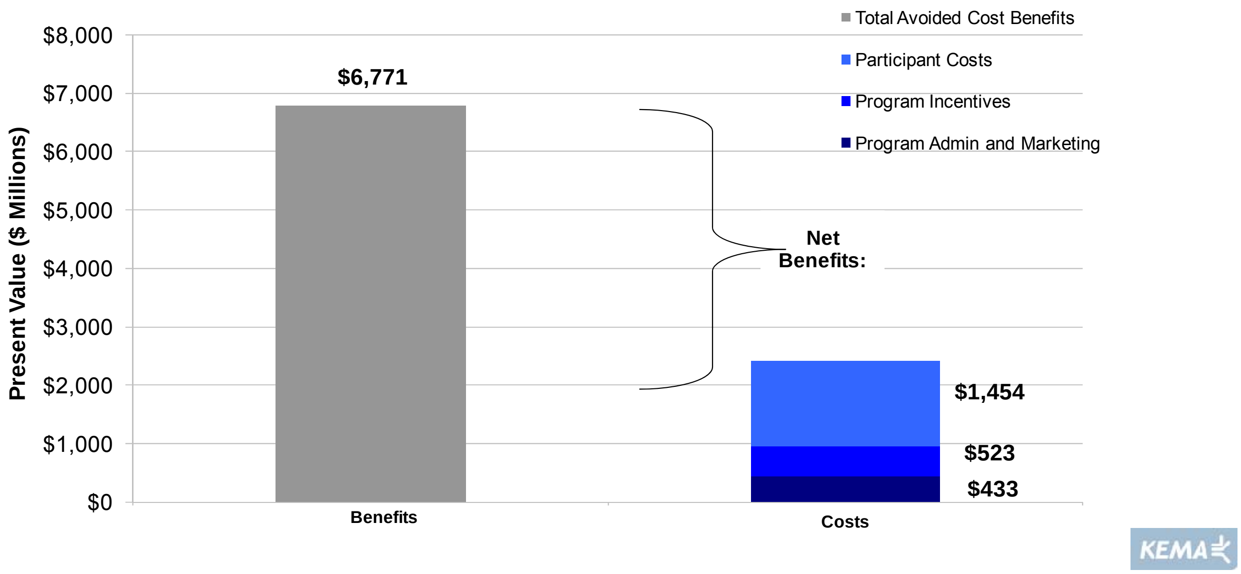


Figure 5-27 below presents the benefit cost relationship for this scenario in graphical format.

Figure 5-27: Overall Benefit Cost Chart – Electric 75 % Incentives



5.2.4 Summary of the 1 year payback scenario

This section presents a summary of the one year payback for incentives scenario. Spending is less in this scenario than the 75 % incentive scenario. It also has a lower benefit cost ratio. Table 5-5 presents a summary of this scenario.

Table 5-5 Summary Table for the Electric One Year Payback Scenario

Result - Programs	Program Scenario: 2011 - 2020			
	Residential	Commercial	Industrial	All Programs
Gross Energy Savings - GWh	4,860	3,114	1,722	9,696
Gross Peak Demand Savings - MW	1,643	446	170	2,259
Net Energy Savings - GWh	3352	1971	1,248	6,571
Net Peak Demand Savings - MW	1433	304	126	1,863
Program Costs - Real, $ Million				
Administration	$139,492,802	$47,331,839	$59,272,264	$246,096,905
Marketing	$67,202,074	$100,300,000	$55,413,542	$222,915,616
Incentives	$1,310,989,486	$606,110,903	$230,728,415	$2,147,828,804
Total	$1,517,684,363	$753,742,742	$345,414,221	$2,616,841,326
PV Avoided Costs	$3,870,474,615	$1,494,748,329	$831,171,000	$6,196,393,944
PV Annual Program Costs (Adm/Mkt)	$165,343,949	$119,357,581	$92,781,203	$377,482,733
PV Net Measure Costs	$1,401,801,129	$634,969,657	$294,275,112	$2,331,045,898
Net Benefits	$2,303,329,538	$740,421,090	$444,114,686	$3,487,865,313
TRC Ratio	2.47	1.98	2.15	2.29

This figure presents the energy savings for the one year payback scenario. Savings are presented for both net savings and for free riders. Demand savings are presented in Figure 5-29.

Figure 5-28: Electric Energy Savings for the 1 Year Payback Scenario

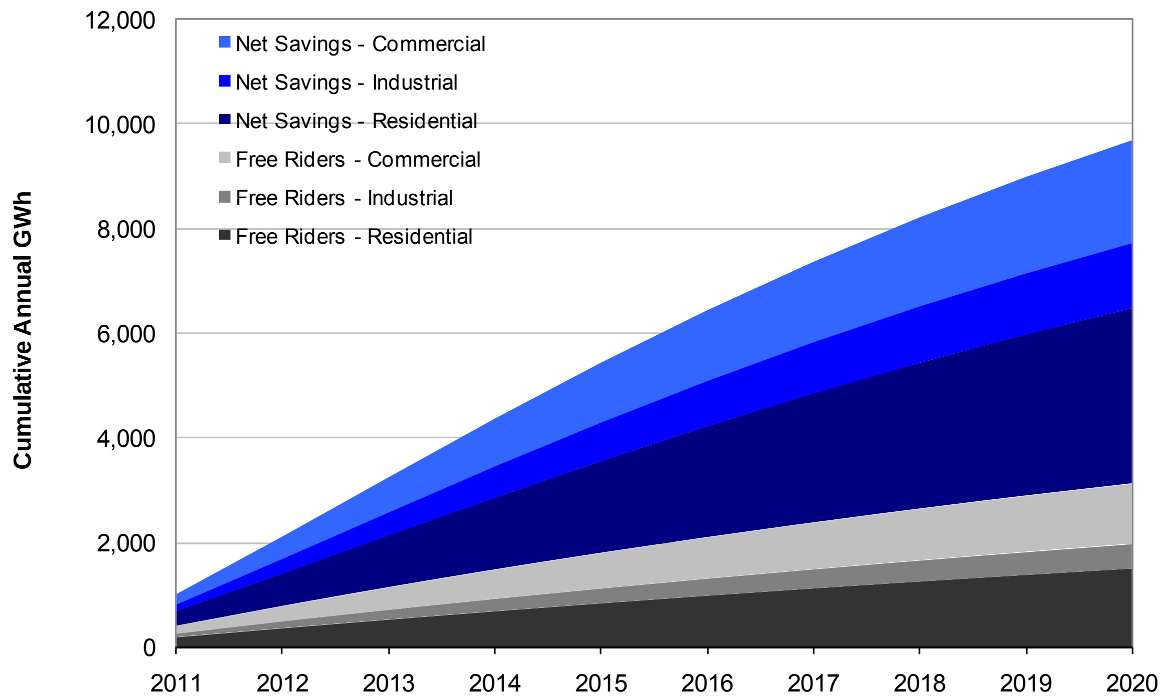


Figure 5-29: Electric Demand Savings for the 1 Year Payback Scenario

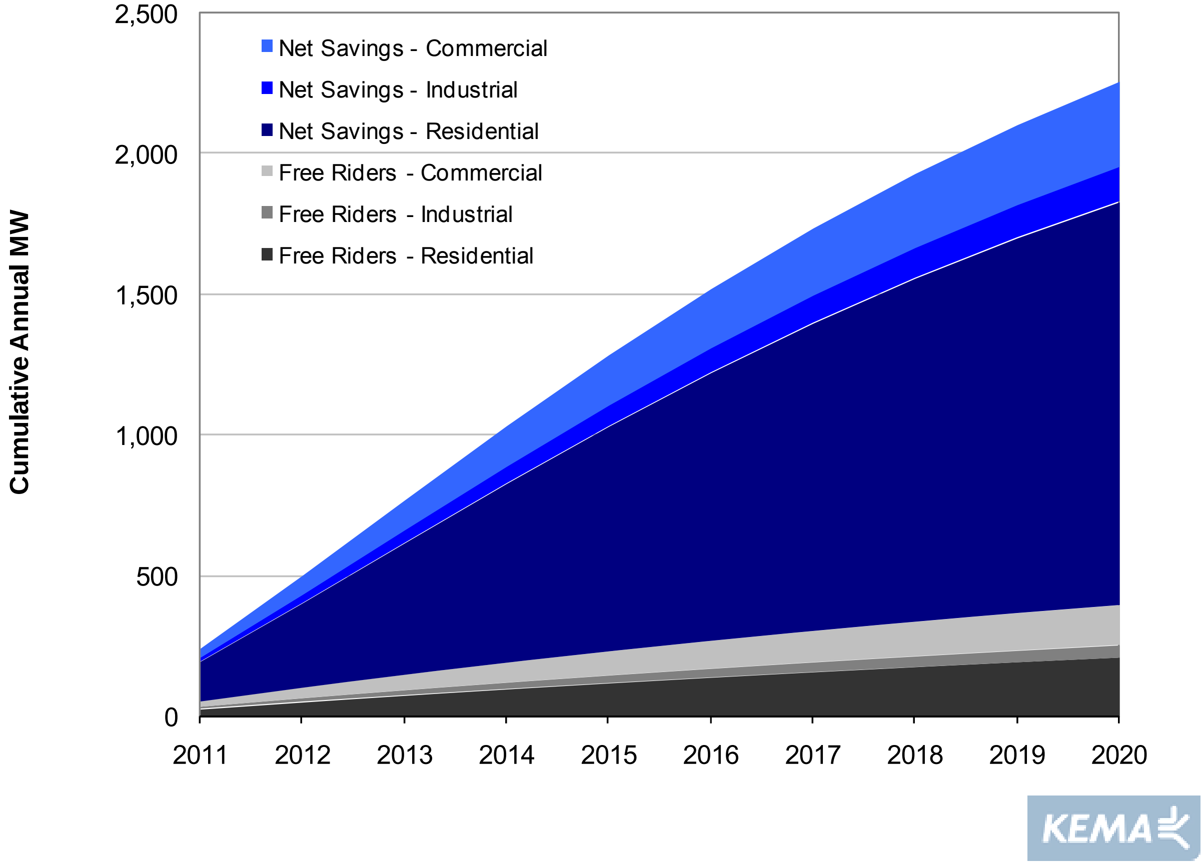
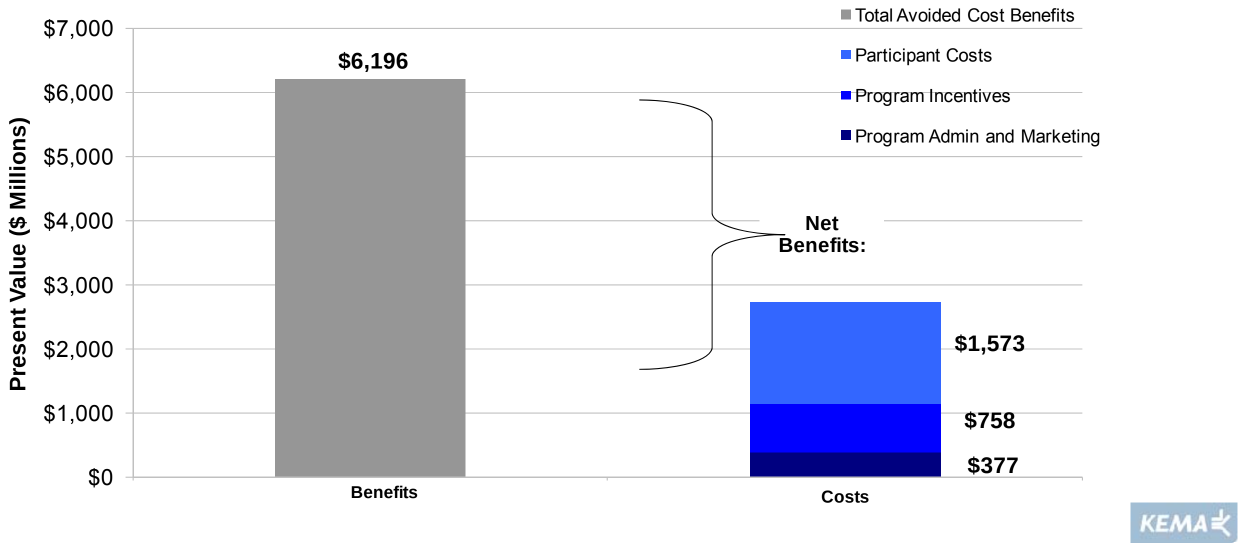


Figure 5-30 below presents the overall cost effectiveness of this scenario.

Figure 5-30 Overall Benefit Cost Chart – Electric 1 Year Payback Scenario



5.2.5 Summary of the 3 year payback scenario

This section presents the summary of the 3 year payback for incentives scenario. Overall budgets are lower than the other scenarios. This is also the least cost effective electric scenario.

Table 5-6 Summary of the Electric Three Year Payback Scenario

Result - Programs	Program Scenario: 2011 - 2020			
	Residential	Commercial	Industrial	All Programs
Gross Energy Savings - GWh	3,045	2,259	1,101	6,406
Gross Peak Demand Savings - MW	754	313	108	1,175
Net Energy Savings - GWh	1538	1116	627	3,281
Net Peak Demand Savings - MW	545	170	63	779
Program Costs - Real, $ Million				
Administration	$92,738,156	$43,092,806	$57,214,821	$193,045,783
Marketing	$67,202,074	$100,300,000	$55,413,542	$222,915,616
Incentives	$352,886,177	$196,001,797	$48,036,816	$596,924,790
Total	$512,826,408	$339,394,603	$160,665,178	$1,012,886,189
PV Avoided Costs	$1,566,700,907	$829,032,115	$400,942,621	$2,796,675,643
PV Annual Program Costs (Adm/Mkt)	$127,953,210	$115,576,622	$89,989,960	$333,519,792
PV Net Measure Costs	$513,947,188	$291,822,283	$121,377,976	$927,147,447
Net Benefits	$924,800,508	$421,633,210	$189,574,685	$1,536,008,404
TRC Ratio	2.44	2.03	1.90	2.22

Figures 5-31 and 5-32 present energy and demand savings overtime for this scenario.

Figure 5-31 Electric Energy Savings in the Three Year Payback Scenario

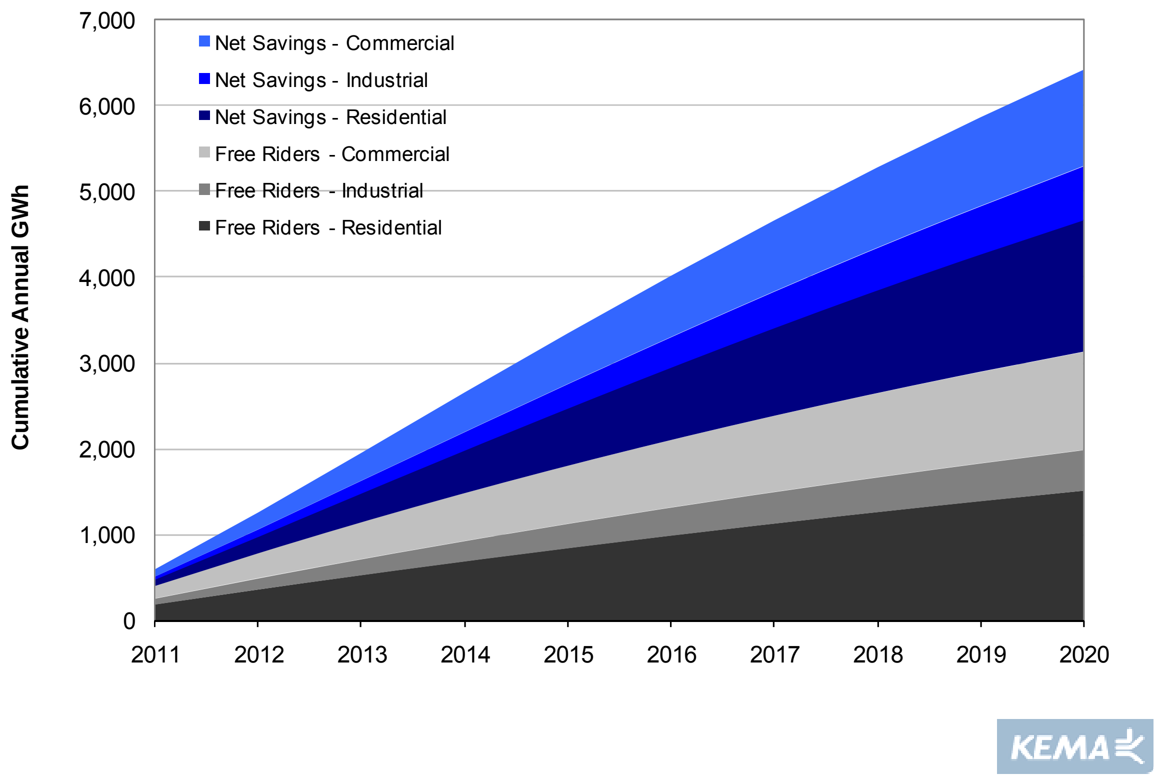


Figure 5-32 Electric Demand Savings in the Three Year Payback Scenario

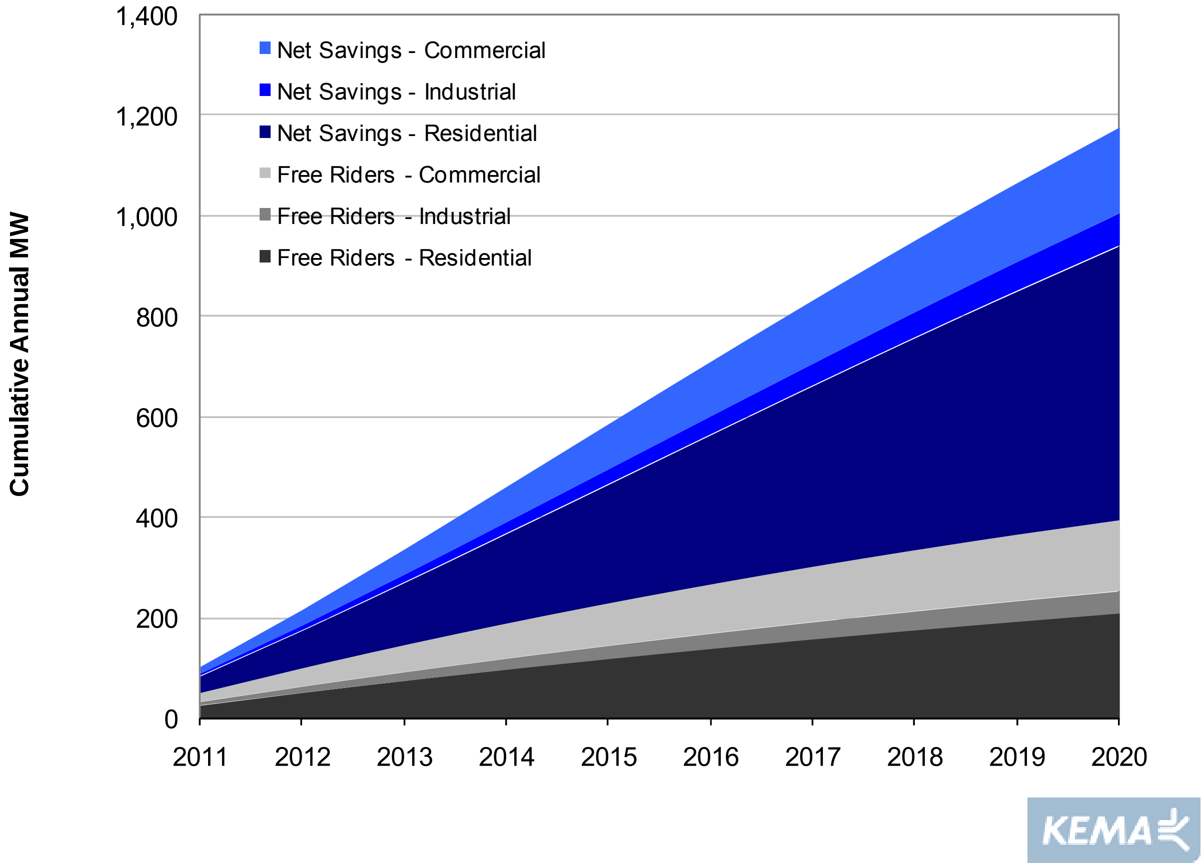
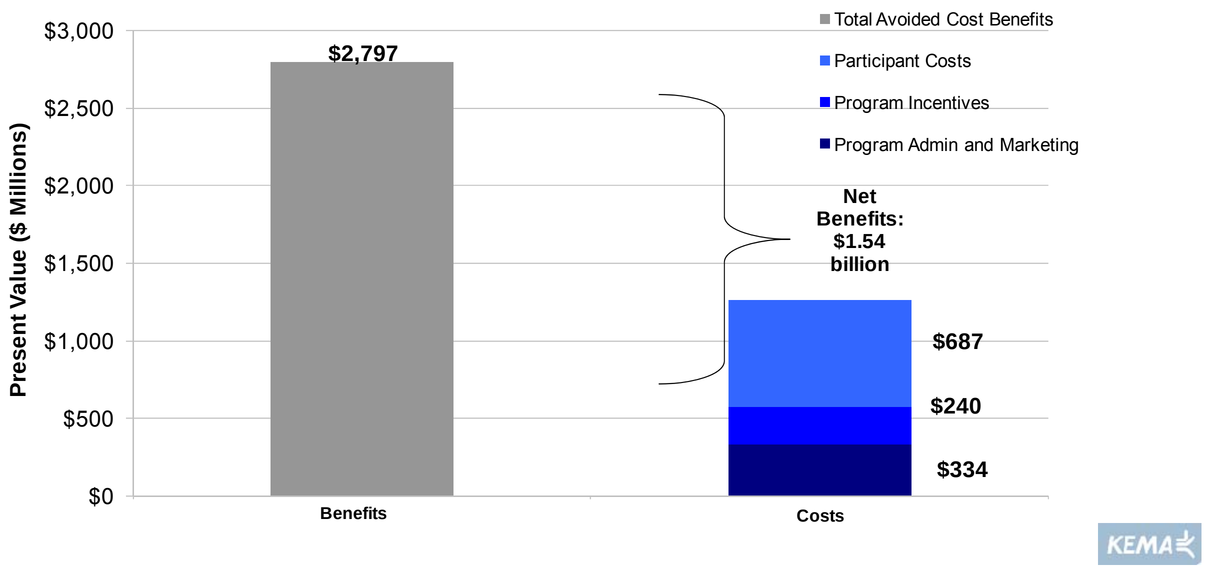


Figure 5-33 presents a summary of the cost effectiveness of this scenario.

5-33 Overall Benefit Cost Chart – Electric Three Year Payback Scenario



6. Natural-Gas Energy-Efficiency Potential Results

In this section, we present estimates of natural-gas energy-efficiency potential. First, we present technical and economic potential results for all electric measures considered in the study. Next, we present estimates of achievable program potential under different program funding scenarios.

6.1 Technical and Economic Potential

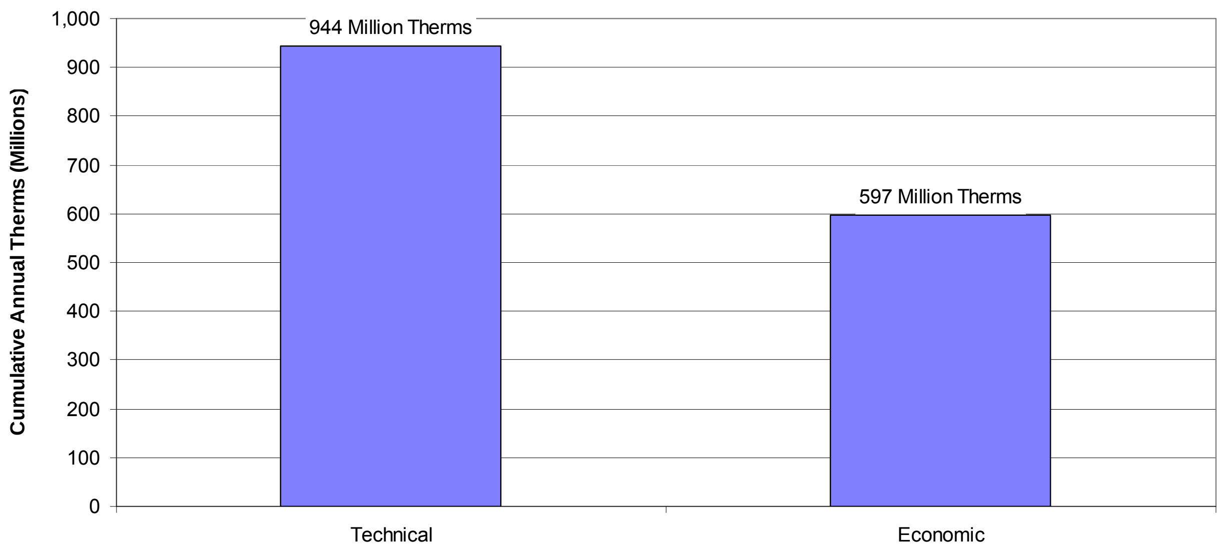
Estimates of overall energy-efficiency technical and economic potential are discussed in section 6.1.1. More detail on these potentials is presented in section 6.1.2. Section 6.1.3 presents the results of alternative avoided cost scenarios considered for the analysis. Energy-efficiency supply curves are shown in Section 6.1.4.

6.1.1 Overall Technical and Economic Potential

Figure 6-1 presents our overall estimates of total technical and economic potential for natural gas energy savings for Missouri. Technical potential represents the sum of all savings from all of the measures deemed applicable and technically feasible. Economic potential is based on efficiency measures that are cost-effective, as determined by the total resource cost (TRC) test—a benefit-cost test that compares the value of avoided energy production and delivery to the costs of energy-efficiency measures and program activities necessary to deliver them.

- Energy Savings. Technical potential is estimated at about 944 million therms per year and economic potential at 597 million therms per year by 2020 (about 37 and 24 percent of base 2020 usage, respectively).

Figure 6-1
Estimated Natural-Gas Technical and Economic Potential, 2020



6.1.2 Technical and Economic Potential Detail

In this subsection, we explore technical and economic potential in more detail, looking at potentials by sector and by end use.

6.1.2.1 Potentials by Sector

Figure 6-2 shows estimates of technical and economic energy-savings potential by sector. Figure 6-3 shows the same potentials as a percentage of 2020 base energy use.

As shown in Figure 6-3, the residential sector has by far the highest technical savings potential in relation to base energy use, but when looking at economic potential, residential and commercial have similar potentials relative to base energy use.

Figure 6-2
Technical and Economic Potential (2020)
Energy Savings by Sector
Millions of Therms per Year

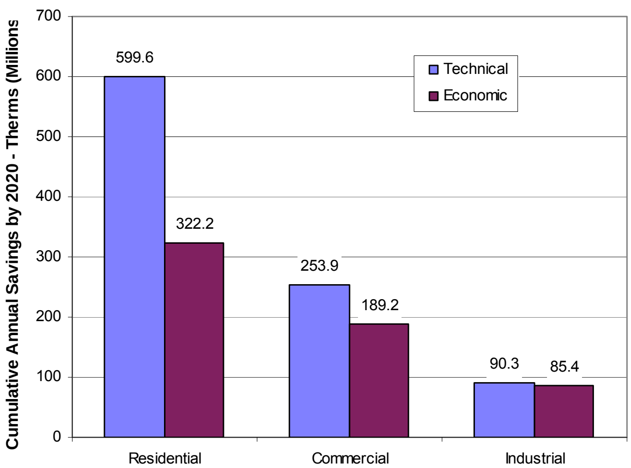


Figure 6-3
Technical and Economic Potential (2020)
Percentage of Base Energy Use

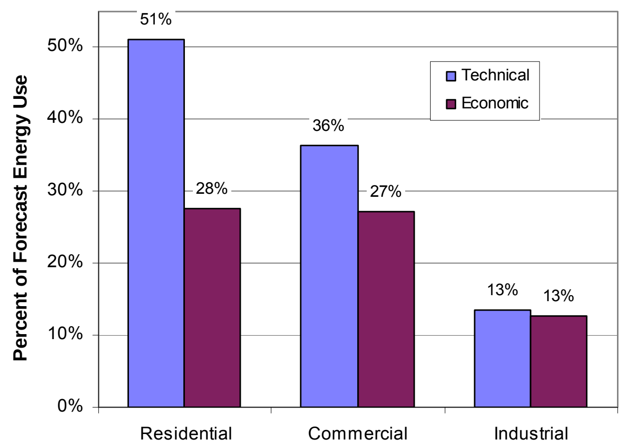
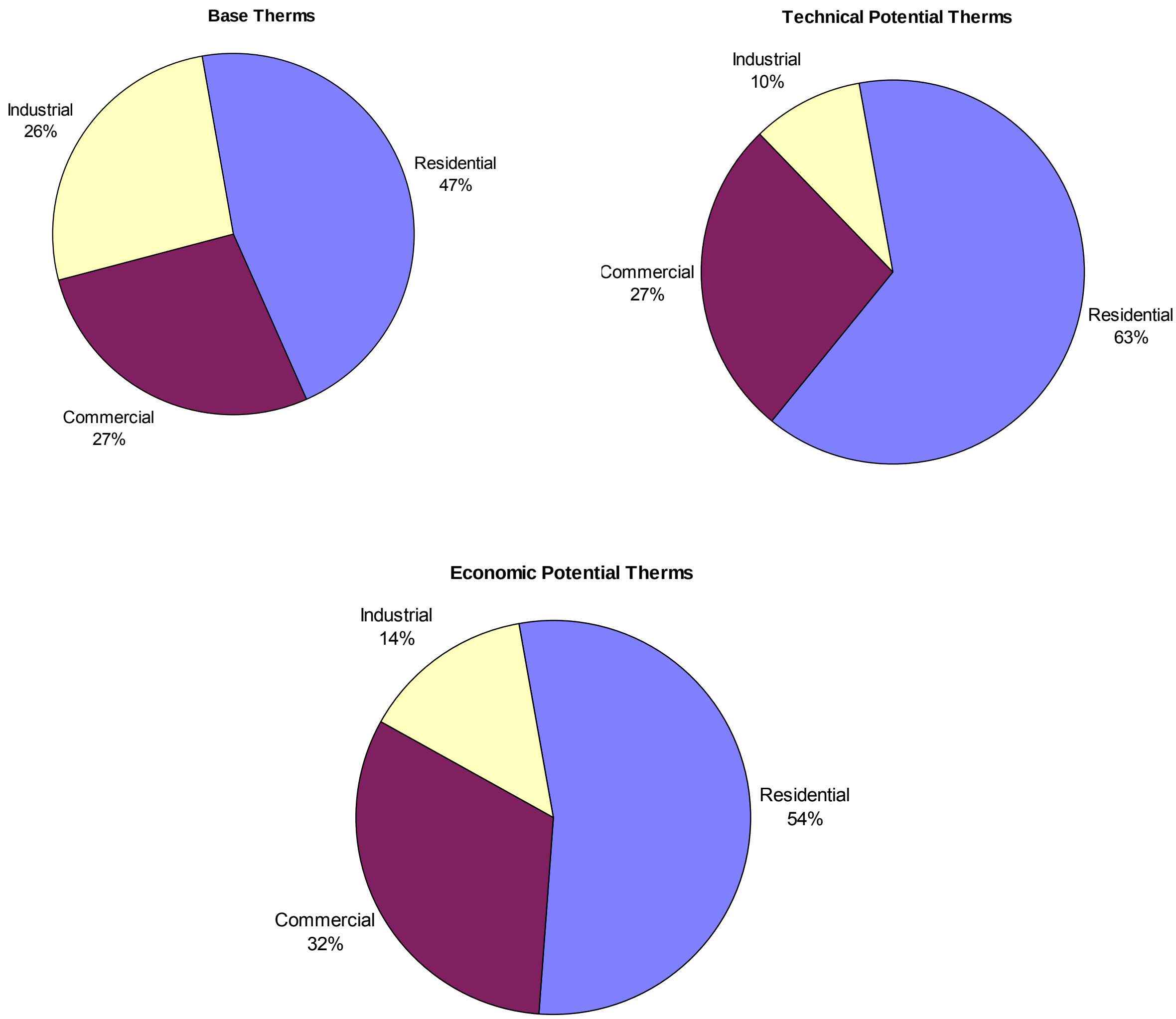


Figure 6-4 shows the relative contribution of the three sectors to base energy use, technical potential and economic potential. The residential sector represents the largest share of base energy, and an even larger share of potential savings. The commercial sectors contribution to technical savings is the same as its share of base use, but its contribution to economic potential is higher, 32 percent compared to 27 percent. Industrial's share of potential is smaller than its share of overall base use.

Figure 6-4
Shares of Base Energy Use, Technical and Economic Energy Potential by Sector



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6.1.2.2 Potentials by Building Type

Figure 6-5 shows the technical and economic potentials in the residential sector by building type. Single-family homes account for more than 90% of the potential (including single-family low income), and low-income homes account for about 27 percent of the potential.

Figure 6-6 shows the building-type breakdown of commercial potential. Offices account for 40 percent of the economic potential, followed by “other” commercial buildings.

Figure 6-5
Residential Energy-Savings Potential by Building Type (2020)

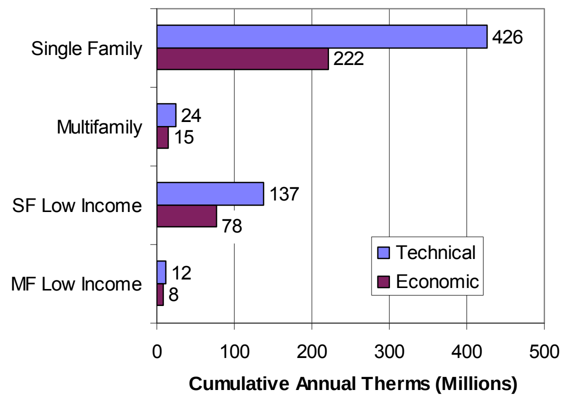


Figure 6-6
Commercial Energy-Savings Potential by Building Type (2020)

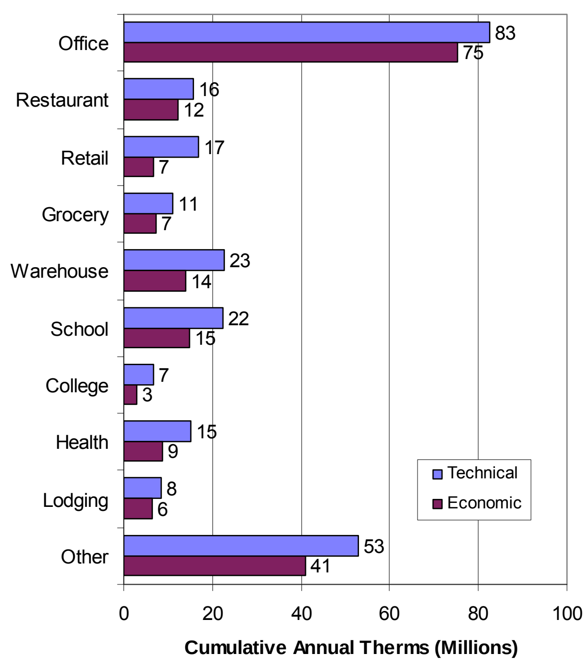
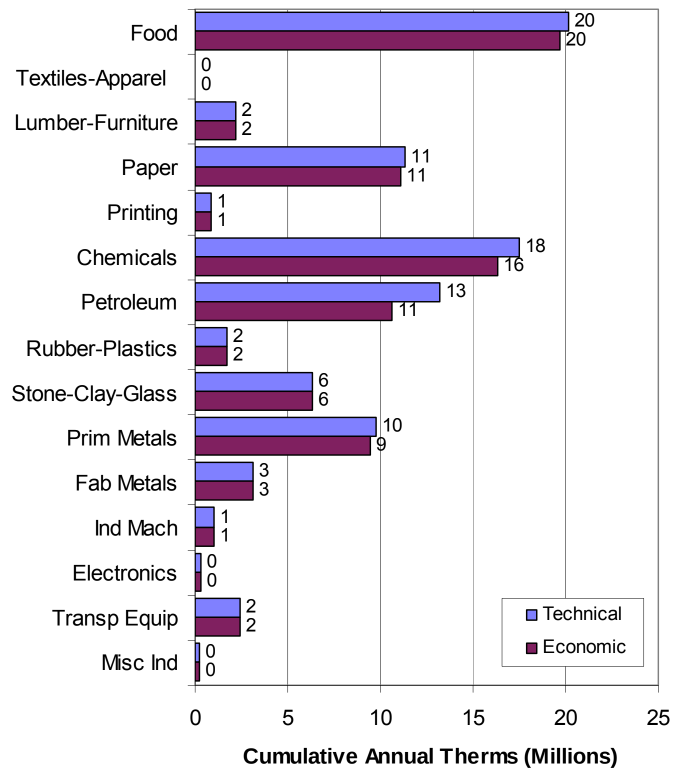


Figure 6-7 shows the business-type breakdown of industrial potential. Key industries in terms of economic potential include food, chemicals, petroleum, paper, and primary metals.

Figure 6-7
Industrial Energy-Savings Potential by Business Type (2020)



6.1.2.3 Potentials by End-Use

Figure 6-8 shows the end-use breakdown of technical and economic potential in the residential sector. Energy-savings potential comes predominantly from space heating and water heating. The whole-building - new construction component also consists mainly of space-heating and water-heating measures. The whole-building – retrofit end use consists of a single behavioral conservation measure.

Figure 6-8
Residential Economic Energy-Savings Potential by End Use (2020)

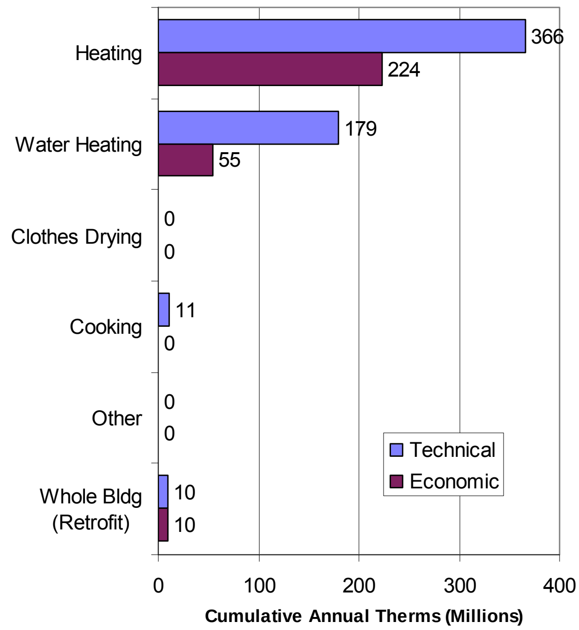


Figure 6-9 shows the end-use breakdown of commercial potential. Space heating is the largest contributor to potentials, followed by water heating and cooking.

Figure 6-9

Commercial Economic Energy-Savings Potential by End Use (2020)

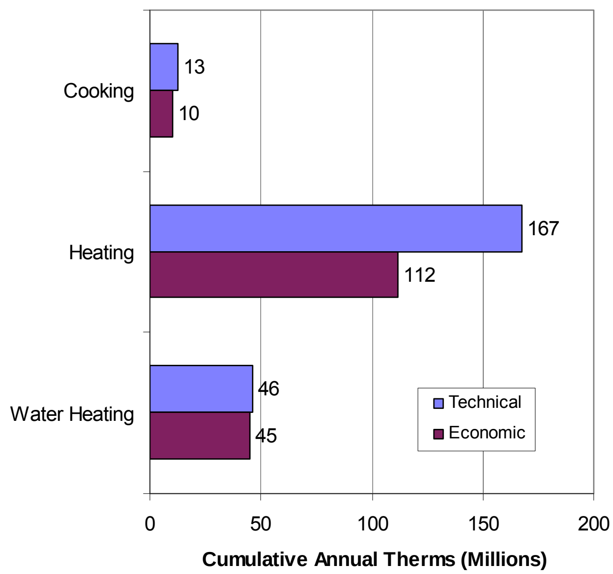
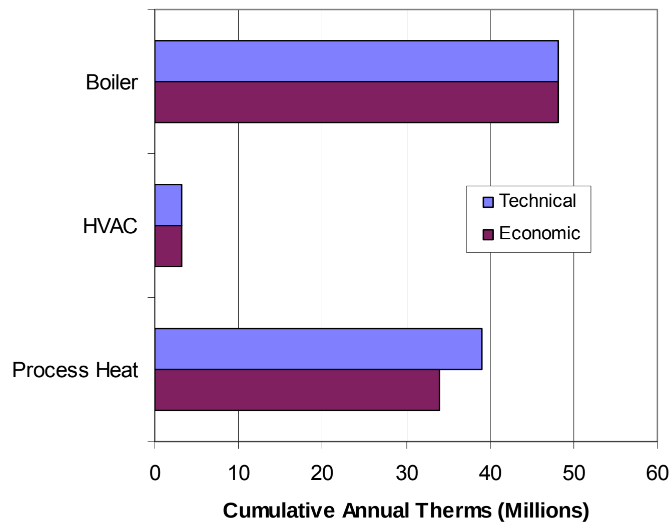


Figure 6-10 shows the end-use breakdown of industrial potential. Boilers have the highest technical and economic saving, followed by process heating. HVAC contributes only a small share to the totals.

Figure 6-10
Industrial Economic Energy-Savings Potential by End Use (2020)



6.1.3 Avoided Cost Scenarios

We examined two alternative avoided cost scenarios in addition to the base scenario. For the low avoided cost scenario, we reduced avoided costs by 20 percent in each year of the forecast. For the high scenario, we increased costs by 50 percent. Figure 6-11 shows technical and economic potential for the three scenarios (technical potential is the same for all three scenarios). In Table 6-1, we compare the three scenarios in terms of percent of sales, percent of technical, and relative to the economic potential of the base avoided cost scenario. The low avoided cost forecast results in economic savings that are 13 percent lower than the base avoided cost forecast, while the high avoided costs result in savings that are 19 percent higher.

Figure 6-11
Estimated Natural-Gas Technical and Economic Potential for Alternative Avoided Cost Scenarios, 2020

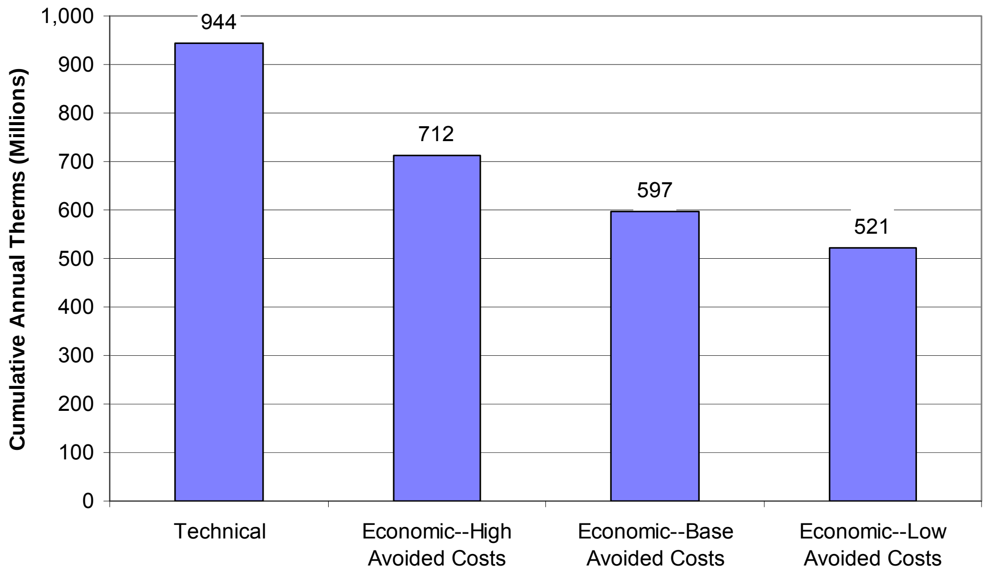


Table 6-1
Comparison of Estimated Natural-Gas Technical and Economic Potential for Alternative Avoided Cost Scenarios, 2020

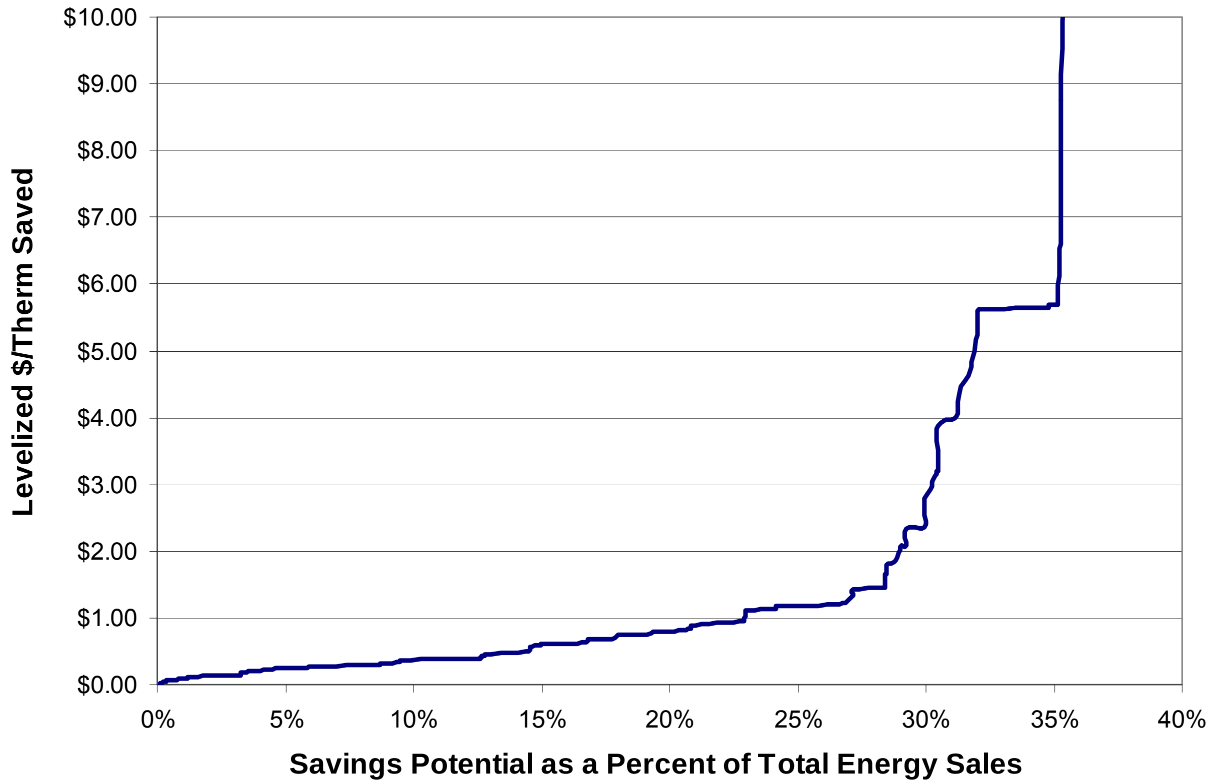
	Sales	Technical Potential	Economic--High Avoided Costs	Economic--Base Avoided Costs	Economic--Low Avoided Costs
Million Therms	2,538	944	712	597	521
% of consumption		37%	28%	24%	21%
% of Technical			75%	63%	55%
% of Economic--Base Avoided Costs			119%	100%	87%

6.1.4 Energy-Efficiency Supply Curves

A common way to illustrate the amount of energy savings per dollar spent is to construct an energy-efficiency supply curve. A supply curve typically is depicted on two axes: one captures the cost per unit of saved energy (e.g., levelized $/therm saved), and the other shows energy savings at each level of cost. Measures are sorted on a least-cost basis, and total savings are calculated incrementally with respect to measures that preceded them. The costs of the measures are levelized over the life of the savings achieved.

Figure 6-12 presents the supply curve constructed for this study for natural gas. The curve represents savings as a percentage of total energy or peak demand. It shows that energy savings of almost 23 percent are available at under $1.00 per therm. Savings potentials and levelized costs for the individual measures that comprise the supply curve are provided in Appendix G.

Figure 6-12
Natural-Gas Supply Curve*



*Levelized cost per kWh saved is calculated using a 7.76 percent nominal discount rate.

6.2 Achievable (Program) Potential

In contrast to technical and economic potential estimates, achievable potential estimates take into account market and other factors that affect the adoption of efficiency measures. We estimate measure adoption while taking into account market barriers and actual consumer- and business-implicit discount rates. This section presents results for achievable potential, first at the summary level and then by scenarios as describe in section 3.3 .

6.2.1 Markets within the scenarios

For each gas scenario we modeled achievable potential by market. We used the following markets:

Table 6-2 Natural Gas Markets and Measures

Customer Sector	Building type	Market	Measures
Residential	Existing	Replace on Burnout	All
Residential	Existing	Retrofit	All
Residential	New	New Construction	All
Commercial	Existing	Replace on Burnout	All
Commercial	Existing	Retrofit	All
Commercial	New	New Construction	All
Industrial	Existing	Replace on Burnout	All
Industrial	Existing	Retrofit	All

Each scenario is build up from these markets.

Achievable potential refers to the amount of savings that would occur in response to one or more specific program interventions. *Net* savings associated with program potential are savings that are projected beyond those that would occur naturally in the absence of any market intervention. Because achievable potential depends on the type and degree of intervention applied, we developed, similar to the electric analysis, potential estimates under three alternative scenarios We estimated program energy savings under each scenario for the 2010-2020 time period. Figure 6-13 shows our estimates of achievable potential savings over time.

Figure 6-13
Achievable Energy Savings: All Sectors

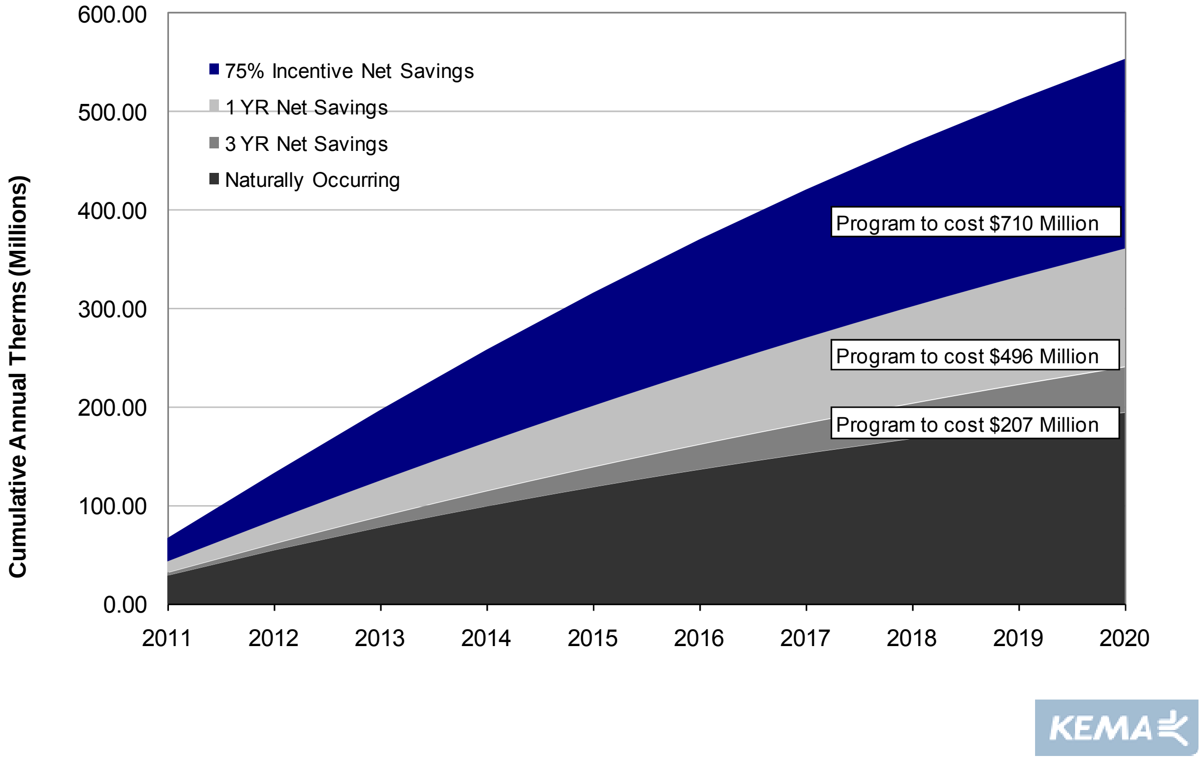
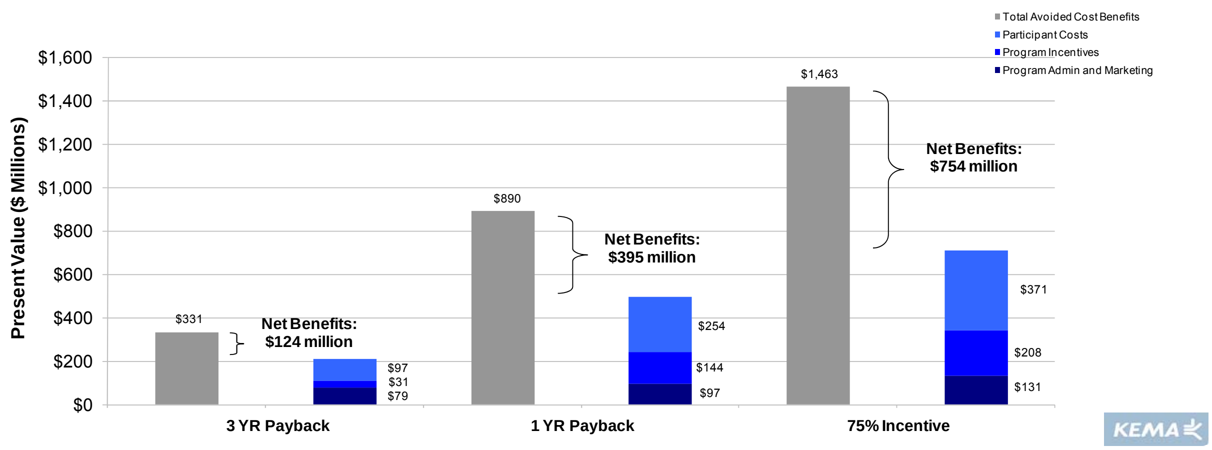


Figure 6-14 depicts costs and benefits under each scenario from 2010 to 2020.

Figure 6-14
Benefits and Costs of Energy-Efficiency Savings—2010-2020*



* Present value of benefits and costs over normalized 20-year measure lives; nominal discount rate is 7.7 percent, inflation rate is 1.5 percent.

All three of the funding scenarios are cost-effective based on the TRC test, which is the test used in this study to determine program cost-effectiveness. The TRC benefit-cost ratios are 1.6 for the three year payback scenario, 1.8 for the one year payback scenario, and 2.1 for the 75% incentive scenario. As will the analysis in the electric sector, the point of diminishing returns was not passed by scenarios in this analysis. Key results of our efficiency scenario forecasts from 2010 to 2020 are summarized in Table 6-3
Summary of Achievable Potential Results—2010-2020.

Table 6-3
Summary of Achievable Potential Results—2010-2020

Result - Programs	3 YR Payback	1 YR Payback	75% Incentive
Gross Energy Savings - Therms (Million	110.8	184.8	257.5
Net Energy Savings - Therms (Millions)	45.8	119.9	192.6
Program Costs - Real, $ Million			
Administration	$64	$87	$128
Marketing	$34	$34	$34
Incentives	$27	$320	$534
Total	$124	$440	$695
PV Avoided Costs	$331	$890	$1,463
PV Annual Program Costs (Adm/Mkt)	$79	$97	$131
PV Net Measure Costs	$129	$398	$578
Net Benefits	$124	$395	$754
TRC Ratio	1.60	1.80	2.06

6.3 Breakdown of Achievable Potential

6.3.1 Summary of the 75 % incentive scenario

This section presents a summary of the 75 % Achievable Scenario. Table 6-4 presents a summary of this scenario in a tabular format for years 2011- 2020 including spending by sector, savings, spending by type and overall avoided cost benefits. The overall benefit / cost ratio for this scenario is 2.06. This scenario is the most cost effective of the scenarios.

Table 6-4 Summary Table for the Gas 75% Incentive Scenario

Result - Programs	Program Scenario: 2011 - 2020 Residential	Commercial	Industrial	All Programs
Gross Energy Savings - Therms (Millions)	158	62	37	257
Net Energy Savings - Therms (Millions)	111	52	30	193
Program Costs - Real, $				
Administration	$97,332,617	$22,605,448	$8,052,714	$127,990,779
Marketing	$10,058,561	$17,251,421	$6,256,368	$33,566,349
Incentives	$388,165,446	$110,640,993	$34,826,977	$533,633,416
Total	$495,556,624	$150,497,861	$49,136,059	$695,190,545
PV Avoided Costs	$851,147,211	$387,536,624	$224,787,580	$1,463,471,414
PV Annual Program Costs (Adm/Mkt)	$87,426,989	$32,187,867	$11,535,092	$131,149,948
PV Net Measure Costs	$417,711,042	$122,133,303	$38,584,536	$578,428,881
Net Benefits	$346,009,179	$233,215,454	$174,667,952	$753,892,586
TRC Ratio	1.68	2.51	4.49	2.06

Figure 6-15 below presents the net energy savings and savings from free riders.

Figure 6-15
Gas Savings by Sector 75 % Incentive Case – units check !!

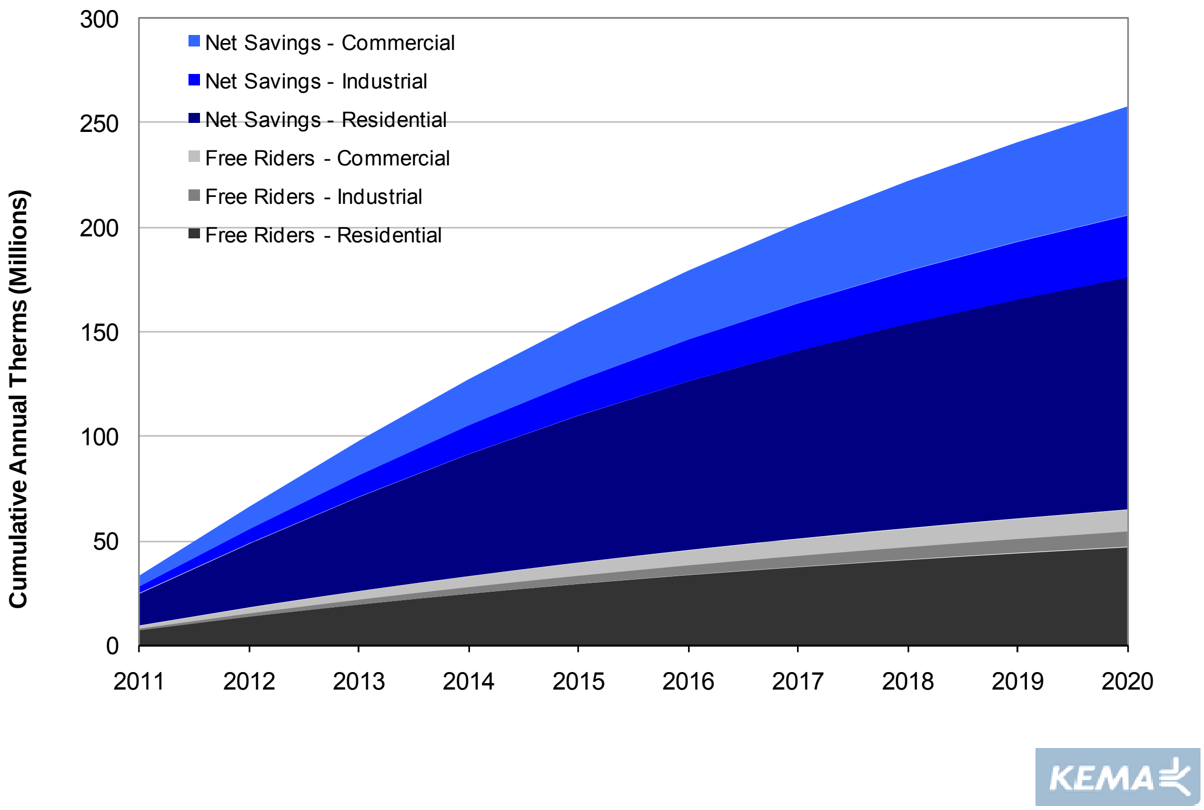
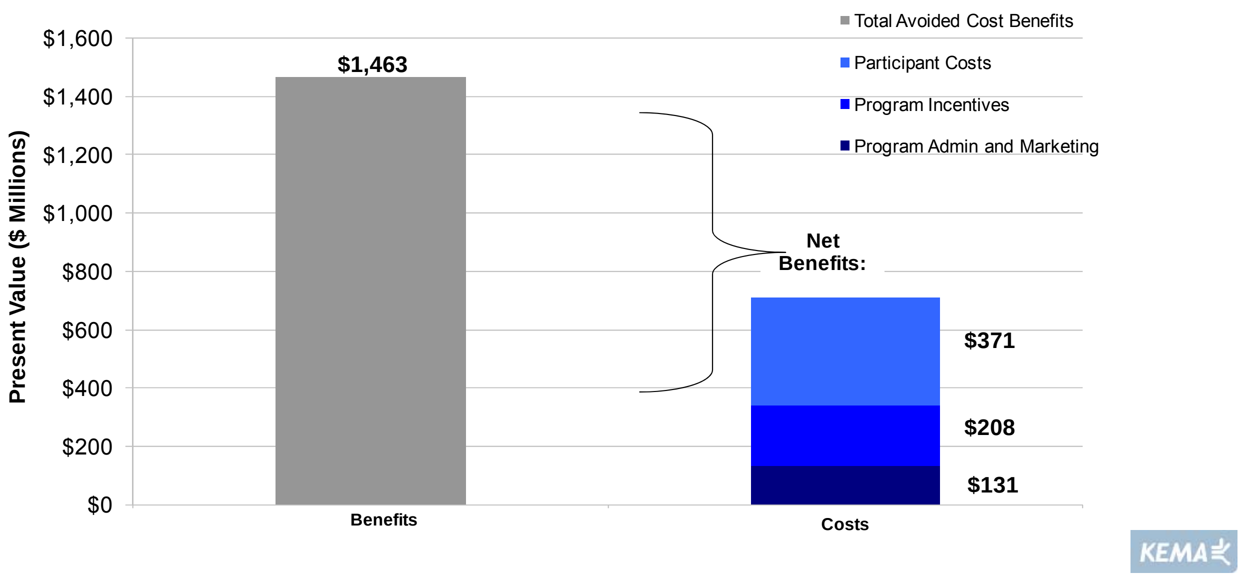


Figure 6-16
Overall Benefit Cost Chart –Gas 75 % Incentives



6.3.2 Summary of the 1 year payback scenario

This section presents a summary of the one year payback for incentives scenario. Spending is less in this scenario than the 75 % incentive scenario. It also has a lower benefit cost ratio. Table 6-5 presents a summary.

Table 6-5 Summary Table for the Gas 1 Year Payback Scenario

Result - Programs	Program Scenario: 2011 - 2020 Residential	Commercial	Industrial	All Programs
Gross Energy Savings - Therms	1,179	465	204	1,848
Gross Peak Demand Savings - Therms/Day	12	6	1	19
Net Energy Savings - Therms	708	362	129	1,199
Net Peak Demand Savings - Therms/Day	8	5	0	13
Program Costs - Real, $ Million				
Administration	$61,422,380	$19,733,859	$5,750,461	$86,906,701
Marketing	$10,058,561	$17,251,421	$6,256,368	$33,566,349
Incentives	$220,499,718	$84,717,487	$14,406,378	$319,623,582
Total	$291,980,659	$121,702,767	$26,413,206	$440,096,632
PV Avoided Costs	$528,314,323	$267,909,908	$94,050,782	$890,275,013
PV Annual Program Costs (Adm/Mkt)	$57,884,996	$29,840,932	$9,598,933	$97,324,862
PV Net Measure Costs	$282,538,873	$95,971,969	$19,915,800	$398,426,642
Net Benefits	$187,890,454	$142,097,007	$64,536,050	$394,523,510
TRC Ratio	1.55	2.13	3.19	1.80

This figure presents the energy savings for the one year payback scenario. Savings are presented for both net savings and for free riders.

Figure 6-17 Gas Energy Savings for the 1 Year Payback Scenario

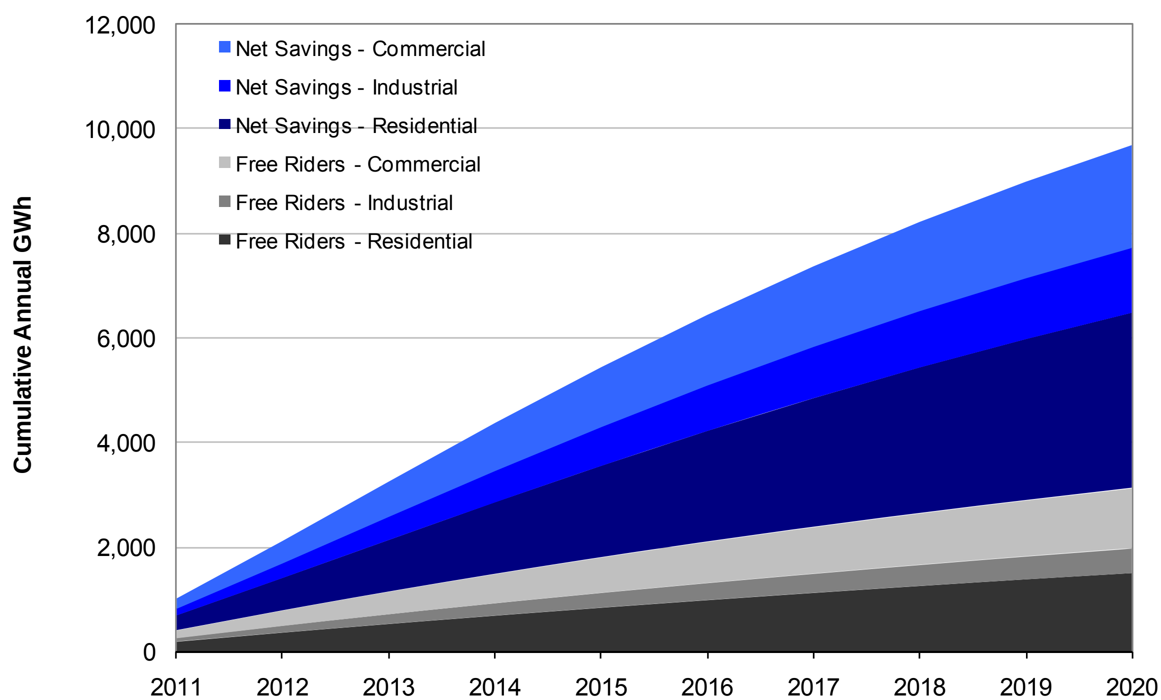
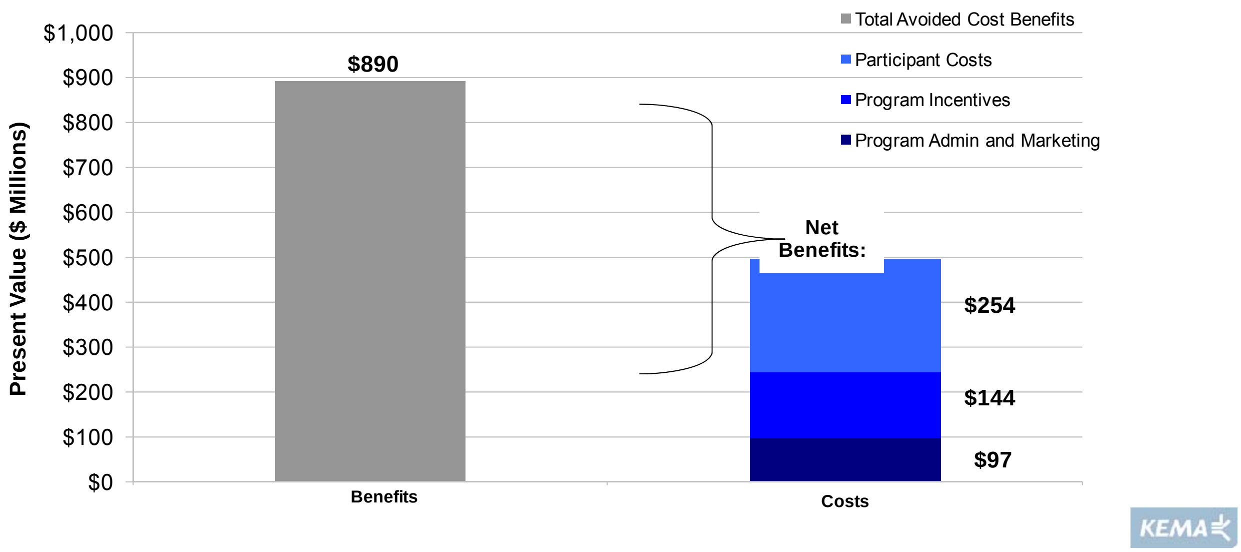


Figure 6-18 below presents the overall cost effectiveness of this scenario.

Figure 6-18 Cost Effectives of 1 Year Payback Scenario



6.3.3 Summary of the 3 year payback scenario

This section presents the summary of the 3 year payback for incentives scenario. Overall budgets are lower than the other scenarios. This is also the least cost effective electric scenario.

Table 6-6 Summary Table for the Gas 3 Year Payback Scenario

Result - Programs	Program Scenario: 2011 - 2020			
	Residential	Commercial	Industrial	All Programs
Gross Energy Savings - Therms (Millions)	78.78	19.99	11.99	110.77
Net Energy Savings - Therms (Millions)	31.64	9.64	4.55	45.83
Program Costs - Real, $				
Administration	$45,192,224	$14,185,888	$4,677,029	$64,055,141
Marketing	$10,058,561	$17,251,421	$6,256,368	$33,566,349
Incentives	$14,162,538	$12,142,215	$487,550	$26,792,303
Total	$69,413,323	$43,579,523	$11,420,947	$124,413,793
PV Avoided Costs	$228,427,479	$70,639,547	$32,040,920	$331,107,947
PV Annual Program Costs (Adm/Mkt)	$44,521,231	$25,365,719	$8,722,019	$78,608,969
PV Net Measure Costs	$101,105,423	$22,347,621	$5,303,396	$128,756,440
Net Benefits	$82,800,826	$22,926,206	$18,015,505	$123,742,537
TRC Ratio	1.57	1.48	2.28	1.60

Figures 6-19 presents energy savings overtime for this scenario.

Figure 6-19
Gas Energy Savings for the 3 Year Payback Scenario

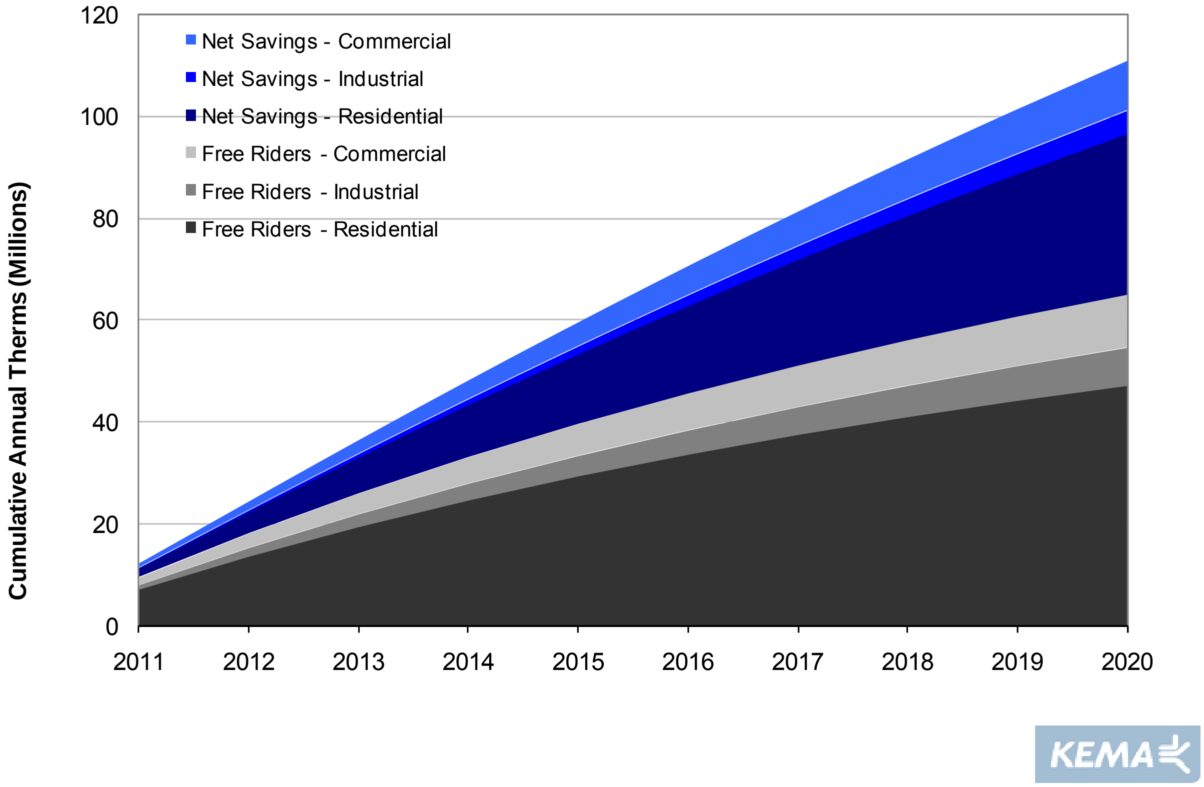
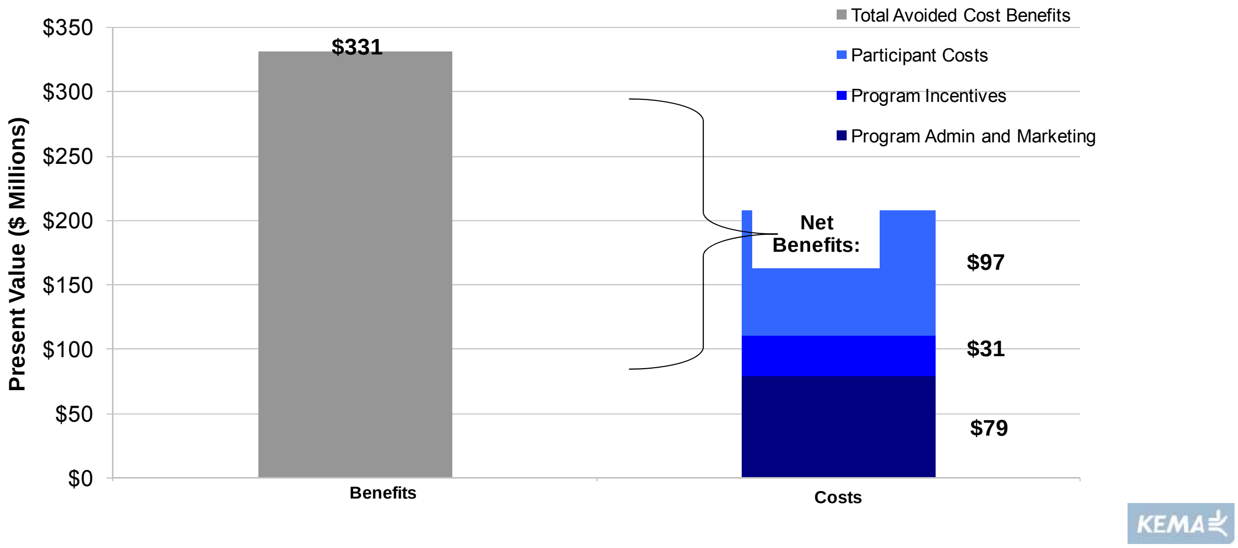


Figure 6-20 presents a summary of the cost effectiveness of this scenario.

Figure 6-20
Overall Benefit Cost Chart –Gas 3 Year Payback Incentives



7. Demand Response Potential Results

7.1 Methodology

KEMA developed an estimate of demand response potential for the State of Missouri using the Federal Energy Regulatory Commission's (FERC's) 2009 National Assessment of Demand Response (NADR) models with specific inputs for the State of Missouri. The NADR model was used to evaluate Missouri demand response potential through 2030. The default inputs for the model were confirmed or adjusted based on information developed during the data collection phase of the project, e.g advanced meter penetrations.

The national study and model implemented a bottom-up approach to estimate DR resources. DR Participation estimates were developed as a percentage of the total customers in each Customer Segment. The four Customer Segments are:

- Residential,
- Small nonresidential,
- Medium nonresidential, and
- Large nonresidential.

The model has the capability of estimating participation in five DR program categories:

- Direct load control,
- Interruptible rates,
- Dynamic pricing with enabling technologies,
- Dynamic pricing without enabling technologies, and
- Other DR programs such as demand bidding.

Participation estimates were developed for four different scenarios:

- Business-as-usual (BAU): BAU assumes current programs and tariffs are held constant;.

- Expanded BAU (EBAU): BAU assumes participation rates are increased to equal the 75th percentile of ranked participation rates of similar programs.

- Achievable Participation (AP): AP assumes advanced metering infrastructure (AMI) is universally deployed, and dynamic pricing is the opt-out default tariff.

- Full Participation (FP): EP assumes that dynamic pricing and the acceptance of enabling technology is mandatory. This scenario quantifies the maximum cost-effective DR potential, absent any regulatory and market barriers.

The NADR model evaluated demand response for the period 2009 through 2019. An evaluation of Missouri DR participation for the period 2010 - 2030 was developed by using the FERC 2009 - 2019 Missouri specific data, adding AMI meter additions identified in this study to the 2010 and 2010 meter totals and developing assumptions consistent with the findings of our research concerning customer, system peak and meter deployment growth for the 2020 - 2030 period. The model was extended through 2030 by projecting the rate of increase in customers, system peak megawatts and AMI meter installations growth from the 2018 to 2019 growth rate.

7.2 FERC Model

The NADR model assumes that demand response (DR) programs are triggered during periods of peak demand. The model output is an estimate of the volume of energy curtailed during a peak demand period. The model is not applicable for estimating the volume of energy that can be curtailed for other purposes such as: avoiding grid congestion, delaying transmission or distribution system capital expenditures, or supporting grid reliability during emergencies.

The model develops an estimate of the quantity of energy curtailed from the following inputs:

- An estimate of the average energy use during peak periods assuming no demand response. The model assumes peak demand will occur 15 hours per year.

- An estimate of the change in energy consumption when a DR program is triggered.

- An estimate of the number of customers participating in the DR program

7.3 Customer Types modeled

The results in this report are based on Missouri specific data embedded in the FERC model. The model divides retail customers into four segments based on common metering and tariff thresholds.

- Residential: includes all residential customers.
- Small commercial and industrial: commercial and industrial customers with summer peak demand less than 20 kilowatts (kW).
- Medium commercial and industrial: commercial and industrial customers with summer peak demand between 20 and 200 kW.
- Large commercial and industrial: demand greater than 200 kW.

7.4 DR Programs Modeled

The FERC analysis[4] assumes five Demand Response (DR) types:

- Dynamic pricing without enabling technology
- Dynamic pricing with enabling technology
- Direct Load Control
- Interruptible tariffs
- “Other”, such as capacity/demand bidding and ISO sponsored programs

Dynamic Pricing (DP) refers to the groups of programs that offer time-varying electricity prices on either a day-ahead or real-time basis. The prices change in response to heavy demand, higher than average costs, and reliability conditions. For the purposes of this model, FERC does not include Time-of-Use (TOU) pricing.

- **DP without enabling technologies** assumes that customers will voluntarily respond to higher on-peak prices by reducing or shifting demand to lower priced off-peak prices. Examples include critical peak pricing and rebates for reducing demand during peaks.

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[4] (FERC, 2009a, Page2)

The FERC model assumes that Advanced Meter Infrastructures (AMI), including “smart meters”, and associated Meter Data Management Systems (MDMS) must be in place. These meters have the capability of measuring customer usage over short period such as 15 minutes.

- **DP with enabling technology** adds devices installed on customer equipment that can automatically reduce consumption during high priced hours. The model assumes that residential and small and medium commercial customers will have programmable communicating thermostats installed on air conditioners. Large commercial and industrial customers are assumed to have automated demand response systems that coordinate the reduction of consumption within the facility

Direct Load Control (DLC) refers to devices installed on customer equipment that are directly controlled by the utility. For the model, residential customers are assumed to have DLC installed only on air conditioners. Non-residential DCL includes air conditioning load and, depending on the State, may include other forms such as irrigation load.

Interruptible Tariff programs, in the FERC model, require customers to reduce consumption to a pre-determined level or specific amount and only during system reliability problems. The programs are generally not available for residential and small commercial customers.

Other DR programs include capacity bidding, demand bidding, aggregator offerings and demand response bid into capacity markets. The program may be triggered by price or reliability. These programs are targeted toward medium and large commercial and large industrial customers.

7.5 Deployment Scenarios

The FERC model analyzes four scenarios.

- Business-As-Usual (BAU)
- Enhanced Business-As-Usual (EBAU)
- Achievable Participation (AP)
- Full Participation (FP)

Business-as-Usual is a measure of existing and planned demand response potential. It serves as a starting point against the other programs can be measured.

Expanded BAU is an estimate of demand response if the current mix of programs achieves "best practices" levels of participation and a modest amount of DR from pricing programs and AMI deployment.

Achievable Participation is an estimate of DR if AMI is universally deployed, DR pricing is the default tariff, and other programs are available for customers who decide to opt-out of dynamic pricing,

Full Participation is an estimate of the total amount of cost-effective demand response given there are no regulatory or market barriers and all customers participate. It represents the upper limit on DR given the assumptions and conditions inherent in the model.

Below is a summary of the key differences in the scenario assumptions. For the purposes of this model, full deployment of AMI is assumed to occur by 2019.

Table 7-1

Key Differences in Scenario Assumptions[5]

Assumption	Business-as-Usual	Expanded BAU	Achievable Participation	Full Participation
AMI deployment	Partial Deployment	Partial deployment	Full deployment	Full deployment
Dynamic pricing participation (of eligible)	Today's level	Voluntary (opt-in); 5%	Default (opt-out); 60% to 75%	Universal (mandatory); 100%
Eligible customers offered enabling tech	None	None	95%	100%
Eligible customers accepting enabling tech	None	None	60%	100%
Basis for non-pricing participation rate	Today's level	"Best practices" estimate	"Best practices" estimate	"Best practices" estimate

7.6 Model Architecture

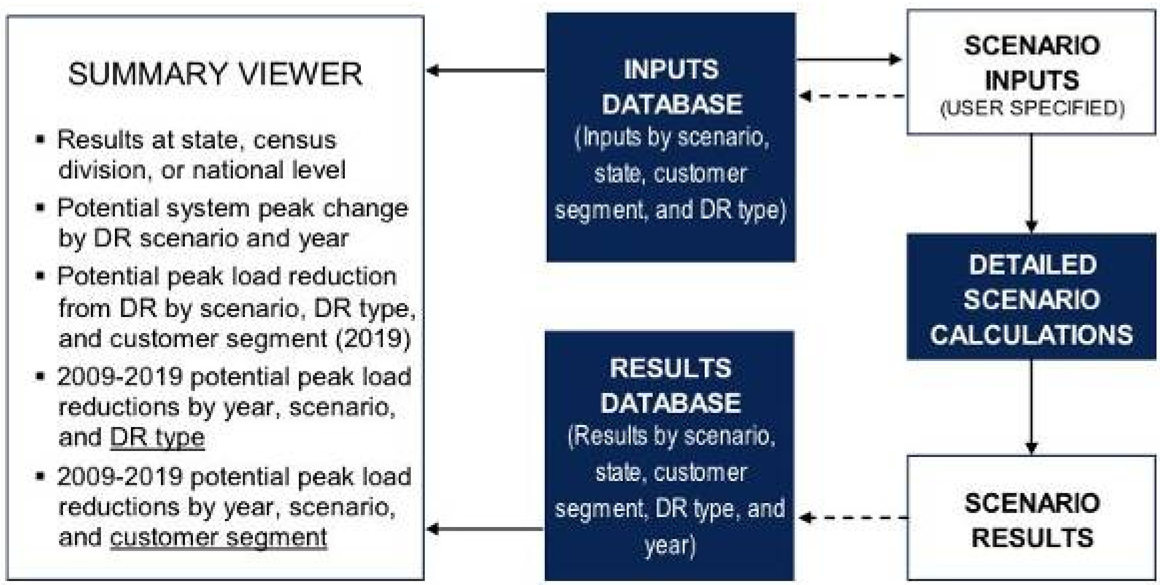
The model[6] is an Excel spreadsheet that takes State specific inputs and runs them through a series of scenarios and outputs the results to a summary page. Scenario inputs are stored in the

[5] (Ferc, 2009b, Page24)

Inputs Database. The Scenario Results Database stores the output from the Detailed Scenario Calculations. Below is a general schematic of the model followed by a summary description of the modeling process.

Figure 7-1

FERC Model Architecture[7]



Scenario Inputs. Region specific customer, peak load, AMI and demand response program information is collected in the Inputs Data sheet.

Scenario Results. Input data is feed in to the model (Detailed Scenario Calculations) calculates DR potential and a Scenario Results Database produced.

Summary Viewer summarizes and displays the information from both the inputs and results database

[6] (FERC, 2009a, Page4)

[7] (FERC, 2009a, Page4)

7.7 Scenario Calculations

Number of Participants in Each Scenario. The number of participants in each DR program is determined by identifying the number of customers eligible to participate in a DR program and assumed participation rates. The number of eligible customers is determined by the customer type and appliance/equipment targeted for reduction. For residential customers, customers with air conditioning were considered eligible. Of those eligible customers, participation rates were determined based on the market penetration of existing DR programs. Except for dynamic pricing, the participation level is set at the percentage participation reached by one quarter of existing program.

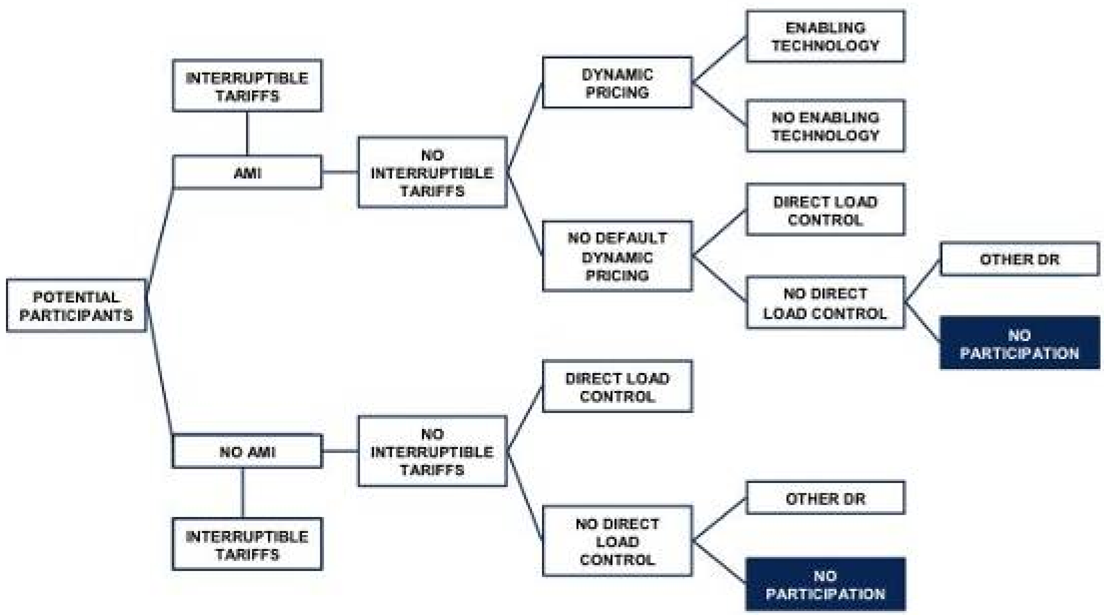
Participation Hierarchy. To prevent double-counting of participants, a hierarchy was established. As shown in Figure 2.3, initially all customers are separated based on the installation of AMI. Customers with interruptible tariffs are assumed not to participate in other DR programs. Customers with AMI traverse the upper path and customers without AMI traverse the lower path.

The next level for customers with AMI is dynamic pricing. Customers with a dynamic pricing tariff may have enabling technology (i.e. programmable thermostats on air conditioners). For customers not on a dynamic pricing tariff, the options are direct load control, other programs (such as demand bidding or ISO/RTO administered program) or no participation.

Customers with AMI, the lower path, have a similar matrix except they are not eligible for a dynamic pricing tariff.

FERC assumes that dynamic pricing options have limited overhead costs particularly if all customers are placed on a dynamic pricing tariff and must take action to op-out out of the tariff. FERC also assumes that dynamic pricing options are not dependent on enabling technologies.

Figure 7-2
Customer Participation Hierarchy Employed in the FERC Model[8]



7.8 Example of Full Participation

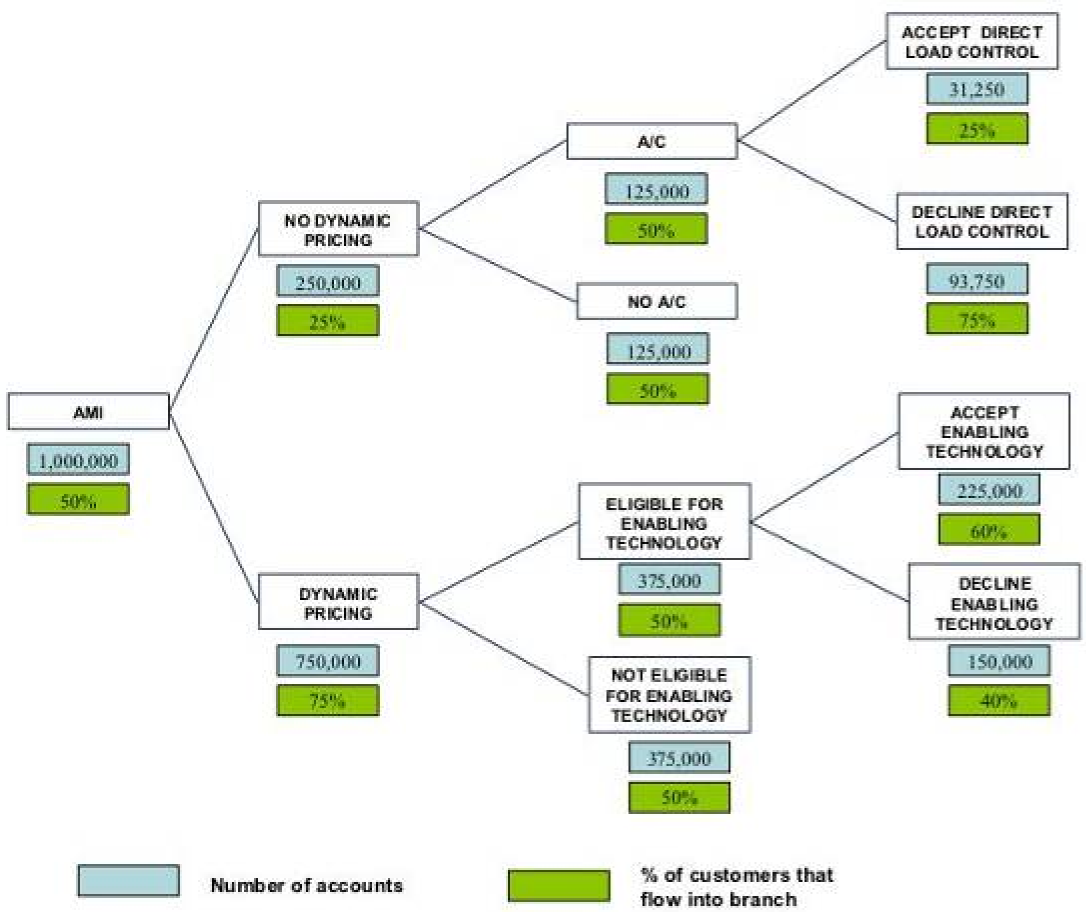
To assist in envisioning the assumed size of the customer pool for each option, FERC provides an example of the hierarchy for residential customers. The example assumes that all residential customers have smart meters and are placed on a dynamic tariff rate. The assumption is that 25% will opt-out of the tariff. Of those remaining, 50% will have air conditioners. 60% of the dynamic rate customers with air conditioners will accept free enabling technology or programmable communicating thermostats (PCT) for their air conditioners.

The model assumes that customers with enabling technology are more likely to curtail and will curtail to a greater extent than customers without enabling technology. Customers without air conditioners are not eligible for enabling technology and are not expected to curtail to the same extent of those with air conditioning. Of the customers with air conditioners that declined to install PCT an achievable penetration rate for direct load control is expected. The result is that

[8] (FERC, 2009a, Page10)

of the 1,000,000 customer with AMI and dynamic pricing, 225,000 (23%) will choose DR using enabling technology.

Figure 7-3
An Example of Enabling Technology and Participation Rates[9]



7.9 Using FERC Full Participation Estimate for Missouri

The FERC model results for 2019 were reviewed to identify Missouri specific assumptions and results. FERC assumes a 45% penetration of AMI meters (Ferc, 2009b Page80), 87.5% saturation of residential central air conditioning and 14.8%(Ferc, 2009bPage238). As noted in

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9 (FERC, 2009a,Page11)

Table 7-2 below, FERC estimated the number of residential customer to be 2,815,113. Assuming the FERC dynamic tariff opt-out rate of 25% applies to Missouri, below is the estimate of the number of residential participants in the dynamic pricing program.

Table 7-2 – FERC Residential Customer Matrix

Matrix Step	Residential Customers
Total 2019 Residential Customers	2,815,113
Customers with AMI (45%)	1,266,801
Customers Accepting Dynamic Pricing Tariff (75%)	950,101
Customers Eligible for Enabling Technology with Central Air Conditioning (87.5%)	831,338
Customers Accepting Enabling Technologies (60%)	498,803
Customer Declining Enabling Technologies (40%)	332,535

In the Full Participation scenario 18% of the total 2019 Missouri residential customers are projected to adopt dynamic pricing using enabling technology.

7.10 Missouri Model Run

Missouri Data Adjustments

During the data collection phase of the project, data was collected on the deployment of advanced meters by utilities in Missouri.

- Elster and Webster Electric Coop - 15,500 smart meters July - December 2010[10]
- SEMO Coop - 16,000 smart meters[11]
- City of Fulton - 5,000 meters - [12]
- Kansas City Power & Light - 14,000 Commercial and Residential[13]

[10] Elster EnergyAxis(R) AMI to replace entire meter base for electric co-op in Missouri

[11] seMissourian.com: Local News: SEMO Electric installs new 'smart' meter system (08/25/10)

[12] SmartGrid.gov: City of Fulton, Missouri Smart Grid Project

Based on the total number of customers the additional meters installations were 1.9% for residential and 0.5% for small commercial customers. This information was added to the model for the years 2010 and 2011. These meters are assumed to be incorporated in the FERC assumption for Missouri of 7.5% for 2012

Extending FERC Model includes Missouri data through 2019. To extend the analysis through 2030 required estimating three sets of inputs:

- Number of Customers
- System Peak Load
- Number of AMI Meters Installed.

7.11 Number of Customers

The estimates were made by assuming the growth rates between 2018 and 2019 continued through 2030. Below are tables of the FERC included data through 2019 and the calculated extensions through 2030 assuming a growth rate of 0.46% for residential customers and 1.07% for commercial and industrial customers.

[13] SmartGrid.gov: Kansas City Power & Light Company Smart Grid Demonstration Project

Table 7-3
Customer Population Growth Rates.

		Commercial & Industrial		
CUSTOMER POPULATION INPUTS	**Residential**	**Small**	**Medium**	**Large**
Growth Rate for years 2020-2030	**0.48%**	**1.07%**	**1.07%**	**1.07%**
Starting Customer Population	**2,670,172**	**347,394**	**25,739**	**4,651**
2009	**2,683,034**	**351,098**	**26,013**	**4,700**
2010	2,695,958	354,841	26,291	4,750
2011	2,708,944	358,624	26,571	4,801
2012	2,721,993	362,448	26,854	4,852
2013	2,735,105	366,312	27,140	4,904
2014	2,748,280	370,218	27,430	4,956
2015	2,761,518	374,165	27,722	5,009
2016	2,774,820	378,154	28,018	5,063
2017	2,788,187	382,186	28,317	5,117
2018	2,801,617	386,260	28,618	5,171
2019	2,815,113	390,378	28,924	5,226
2020	*2,828,673*	*394,540*	*29,232*	*5,282*
2021	*2,842,299*	*398,747*	*29,544*	*5,338*
2022	*2,855,990*	*402,998*	*29,859*	*5,395*
2023	*2,869,747*	*407,295*	*30,177*	*5,453*
2024	*2,883,571*	*411,637*	*30,499*	*5,511*
2025	*2,897,461*	*416,026*	*30,824*	*5,570*
2026	*2,911,418*	*420,461*	*31,152*	*5,629*
2027	*2,925,442*	*424,944*	*31,485*	*5,689*
2028	*2,939,534*	*429,475*	*31,820*	*5,750*
2029	*2,953,693*	*434,054*	*32,159*	*5,811*
2030	*2,967,921*	*438,681*	*32,502*	*5,873*

7.12 System Peak

System peak values for 2020 through 2030 were estimated assuming the growth rate was constant and equal to the rate of growth between 2018 and 2019. The growth rate between 2018 and 2019 was calculated to be 1.68%. That rate was applied to estimate the peak demand growth between 2020 and 2030. The peak demand for those years is included in Tables 7-4 through 7-7.

7.13 Number of AMI Meters

In the FERC model, the level of demand reduction is partly driven by the number of AMI meters installed. The BAU and EAU scenarios assume a slower rate of AMI deployment than the AP and FP scenarios. For the BAU and EBAU scenarios, the rate of deployment for 2018 to 2019 was assumed to continue through 2030. That rate was calculated to be 5.72%. The FERC model assumes full deployment of AMI meters by 2019. This rate was extended through 2030. The assumed penetration of AMI for each of the scenarios is shown in Tables 7-4 through 7-7.

Table 7-4
BAU Data Inputs for System Peak and AMI Meters

BAU	System Peak Forecast	Advanced Metering Infrastructure Deployment			
			Commercial & Industrial		
YEARLY SYSTEM PEAK AND AMI DEPLOYMENT INPUTS	**(MW)**	**Residential**	**Small**	**Medium**	**Large**
2009	17,739	0.0%	0.0%	0.0%	0.0%
2010	18,102	**1.9%**	**0.5%**	0.0%	0.0%
2011	18,424	**1.9%**	**0.5%**	0.0%	0.0%
2012	18,728	**7.5%**	**7.5%**	**7.5%**	**7.5%**
2013	19,053	**15.0%**	**15.0%**	**15.0%**	**15.0%**
2014	19,408	**24.0%**	**24.0%**	**24.0%**	**24.0%**
2015	19,755	**33.0%**	**33.0%**	**33.0%**	**33.0%**
2016	20,090	**36.4%**	**36.4%**	**36.4%**	**36.4%**
2017	20,434	**40.0%**	**40.0%**	**40.0%**	**40.0%**
2018	20,783	**42.6%**	**42.6%**	**42.6%**	**42.6%**
2019	21,139	**45.2%**	**45.2%**	**45.2%**	**45.2%**
2020	*21,495*	*47.8%*	*47.8%*	*47.8%*	*47.8%*
2021	*21,857*	*50.5%*	*50.5%*	*50.5%*	*50.5%*
2022	*22,224*	*53.4%*	*53.4%*	*53.4%*	*53.4%*
2023	*22,598*	*56.5%*	*56.5%*	*56.5%*	*56.5%*
2024	*22,978*	*59.7%*	*59.7%*	*59.7%*	*59.7%*
2025	*23,365*	*63.1%*	*63.1%*	*63.1%*	*63.1%*
2026	*23,758*	*66.7%*	*66.7%*	*66.7%*	*66.7%*
2027	*24,158*	*70.5%*	*70.5%*	*70.5%*	*70.5%*
2028	*24,565*	*74.6%*	*74.6%*	*74.6%*	*74.6%*
2029	*24,978*	*78.8%*	*78.8%*	*78.8%*	*78.8%*
2030	*25,398*	*83.3%*	*83.3%*	*83.3%*	*83.3%*
Assume 2018 to 2019 growth rate	**0.0168**	**0.0572**	**0.05721**	**0.0572**	**0.0572**

Table 7-5
Enhanced BAU Data Inputs for System Peak and AMI Meters

Expanded BAU	System Peak Forecast	Advanced Metering Infrastructure Deployment			
			Commercial & Industrial		
YEARLY SYSTEM PEAK AND AMI DEPLOYMENT INPUTS	**(MW)**	**Residential**	**Small**	**Medium**	**Large**
2009	17,739	0.0%	0.0%	0.0%	0.0%
2010	18,102	**1.9%**	**0.5%**	0.0%	0.0%
2011	18,424	**1.9%**	**0.5%**	0.0%	0.0%
2012	18,728	**7.5%**	**7.5%**	**7.5%**	**7.5%**
2013	19,053	**15.0%**	**15.0%**	**15.0%**	**15.0%**
2014	19,408	**24.0%**	**24.0%**	**24.0%**	**24.0%**
2015	19,755	**33.0%**	**33.0%**	**33.0%**	**33.0%**
2016	20,090	**36.4%**	**36.4%**	**36.4%**	**36.4%**
2017	20,434	**40.0%**	**40.0%**	**40.0%**	**40.0%**
2018	20,783	**42.6%**	**42.6%**	**42.6%**	**42.6%**
2019	21,139	**45.2%**	**45.2%**	**45.2%**	**45.2%**
2020	*21,495*	*47.8%*	*47.8%*	*47.8%*	*47.8%*
2021	*21,857*	*50.5%*	*50.5%*	*50.5%*	*50.5%*
2022	*22,224*	*53.4%*	*53.4%*	*53.4%*	*53.4%*
2023	*22,598*	*56.5%*	*56.5%*	*56.5%*	*56.5%*
2024	*22,978*	*59.7%*	*59.7%*	*59.7%*	*59.7%*
2025	*23,365*	*63.1%*	*63.1%*	*63.1%*	*63.1%*
2026	*23,758*	*66.7%*	*66.7%*	*66.7%*	*66.7%*
2027	*24,158*	*70.5%*	*70.5%*	*70.5%*	*70.5%*
2028	*24,565*	*74.6%*	*74.6%*	*74.6%*	*74.6%*
2029	*24,978*	*78.8%*	*78.8%*	*78.8%*	*78.8%*
2030	*25,398*	*83.3%*	*83.3%*	*83.3%*	*83.3%*
Assume 2018 to 2019 growth rate	**0.0168**	**0.0572**	**0.0572**	**0.0572**	**0.0572**

Table 7-6

Achievable Participation Data Inputs for System Peak and AMI Meters

Achievable Participation	System Peak Forecast	Advanced Metering Infrastructure Deployment			
			Commercial & Industrial		
YEARLY SYSTEM PEAK AND AMI DEPLOYMENT INPUTS	**(MW)**	**Residential**	**Small**	**Medium**	**Large**
2009	17,739	0.0%	0.0%	0.0%	0.0%
2010	18,102	**1.9%**	**0.5%**	0.0%	0.0%
2011	18,424	**1.9%**	**0.5%**	0.0%	0.0%
2012	18,728	**11.2%**	**11.2%**	**11.2%**	**11.2%**
2013	19,053	**22.4%**	**22.4%**	**22.4%**	**22.4%**
2014	19,408	**38.1%**	**38.1%**	**38.1%**	**38.1%**
2015	19,755	**53.8%**	**53.8%**	**53.8%**	**53.8%**
2016	20,090	**63.6%**	**63.6%**	**63.6%**	**63.6%**
2017	20,434	**76.7%**	**76.7%**	**76.7%**	**76.7%**
2018	20,783	**88.4%**	**88.4%**	**88.4%**	**88.4%**
2019	21,139	**100.0%**	**100.0%**	**100.0%**	**100.0%**
2020	*21,495*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2021	*21,857*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2022	*22,224*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2023	*22,598*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2024	*22,978*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2025	*23,365*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2026	*23,758*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2027	*24,158*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2028	*24,565*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2029	*24,978*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2030	*25,398*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
Assumed 2018 to 2019 growth rate	**0.0168**				

Table 7-7
Full Participation Data Inputs for System Peak and AMI Meters

Full Participation	System Peak Forecast	Advanced Metering Infrastructure Deployment			
			Commercial & Industrial		
YEARLY SYSTEM PEAK AND AMI DEPLOYMENT INPUTS	**(MW)**	**Residential**	**Small**	**Medium**	**Large**
2009	17,739	0.0%	0.0%	0.0%	0.0%
2010	18,102	**1.9%**	**0.5%**	0.0%	0.0%
2011	18,424	**1.9%**	**0.5%**	0.0%	0.0%
2012	18,728	11.2%	11.2%	11.2%	11.2%
2013	19,053	22.4%	22.4%	22.4%	22.4%
2014	19,408	38.1%	38.1%	38.1%	38.1%
2015	19,755	53.8%	53.8%	53.8%	53.8%
2016	20,090	63.6%	63.6%	63.6%	63.6%
2017	20,434	76.7%	76.7%	76.7%	76.7%
2018	20,783	88.4%	88.4%	88.4%	88.4%
2019	21,139	100.0%	100.0%	100.0%	100.0%
2020	*21,495*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2021	*21,857*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2022	*22,224*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2023	*22,598*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2024	*22,978*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2025	*23,365*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2026	*23,758*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2027	*24,158*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2028	*24,565*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2029	*24,978*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2030	*25,398*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
Assume 2018 to 2019 growth rate	**0.0168**				

7.14 Study Results

The FERC model was run in two parts. The default Missouri data for years 2009 through 2019 was augmented with the additional AMI information and then solved. A new model sheet was created and populated with the 2020 through 2030 estimated data and solved. The five year results are provided in Tables 7-8 and 7-9.

Table 7-8 provides a summary of demand reduction by scenario in both megawatts reduced and percentage of peak demand. Under the BAU scenario, the model predicts a reduction of one percent in peak demand is estimated. The Expanded BAU scenario predicts that peak demand savings will increase to 8% when participation in Missouri is modeled at 75% of best practices across all other jurisdictions. Under the Achievable and Full Potential scenarios the model predicts peak demand reductions of 13% and 17% respectively in 2030.

Table 7-8
Model Results for Missouri, Years 2009 Through 2030

Year	System Peak (without DR)	Business As Usual	Expanded BAU	Achievable Participation	Full Participation
MW Reduction					
2010	18,102	17,820	17,414	17,414	17,414
2015	19,755	19,473	17,921	17,356	16,812
2020	21,495	21,213	19,595	18,513	17,443
2025	23,365	23,083	21,383	20,272	19,166
2030	25,398	25,116	23,328	22,188	21,045
Percentage Reduction					
2010	18,102	2%	2%	2%	2%
2015	19,755	1%	2%	12%	12%
2020	21,495	1%	9%	14%	19%
2025	23,365	1%	8%	13%	18%
2030	25,398	1%	8%	13%	17%

Disaggregation of the saving achieved by program and mechanism is shown in Table 7-9 below. The model estimates that demand reductions in the BAU scenario will be driven by customers under interruptible tariffs. The Expanded BAU scenario estimates that the major drivers for peak demand reduction will be interruptible tariff and direct load control programs. Both Achievable and Full Participation scenarios are heavily driven by customer participation in dynamic pricing with and without enabling technologies over direct load control with interruptible tariff customers continuing to participate at Expanded BAU rates.

Table 7-9 – Summary Demand Response Results

Program mechanism	2010	2015	2020	2025	2030
	MW	MW	MW	MW	MW
BAU					
Pricing With Enabling Technology	0	0	0	0	0
Pricing Without Enabling Technology	0	0	0	0	0
Automated or Direct Control DR	63	63	63	63	63
Interruptible Tariffs	219	219	219	219	219
Other DR	0	0	0	0	0
TOTAL	**282**	**282**	**282**	**282**	**282**
Expanded BAU					
Pricing With Enabling Technology	0	0	0	0	0
Pricing Without Enabling Technology	0	31	46	62	85
Automated or Direct Control DR	336	839	850	864	875
Interruptible Tariffs	326	647	677	713	752
Other DR	26	316	328	343	358
TOTAL	**688**	**1833**	**1900**	**1982**	**2070**
Achievable Participation					
Pricing With Enabling Technology	0	660	1255	1294	1335
Pricing Without Enabling Technology	0	353	674	697	722
Automated or Direct Control DR	336	521	241	247	252
Interruptible Tariffs	326	647	677	713	752
Other DR	26	218	134	142	149
TOTAL	**688**	**2399**	**2982**	**3093**	**3210**
Full Participation Potential					
Pricing With Enabling Technology	0	1599	3045	3142	3243
Pricing Without Enabling Technology	0	139	268	281	296
Automated or Direct Control DR	336	409	63	63	63
Interruptible Tariffs	326	647	677	713	752
Other DR	26	149	0	0	0
TOTAL	**688**	**2942**	**4052**	**4200**	**4353**

7.15 Cost-effectiveness Overview

The FERC assessment focuses on programs that reduce consumption during periods of high demand. These programs are modeled to reduce demand between 2 and 6 PM on the 15 peak days per year. Some stakeholders may consider untenable the significant deployment of time and resources to manage demand for 60 hours. If managing transmission congestion and system reliability during emergencies are included in the overall analysis of demand response programs, then the DR program has an opportunity to provide Missouri customers with benefits throughout the year.

Nonetheless, a review of Missouri data showed that a direct load control provided more benefit for the same enabling technology cost. FERC performed a cost effectiveness analysis for each State (Ferc, 2009b, Page238). They estimated the cost of enabling technology. Table D-15 from the report shows the cost of a programmable control thermostat (PCT) to be equivalent to a direct load control switch. Below is the table reproduced for residential, and C&I customers.

Table 7-10

Existing Technology Equipment Costs (from FERC 2009b, Table D-15)

Customer	Dynamic Pricing		Direct Load Control	
Type	Equipment	Unit Cost	Equipment	Unit Cost
Residential	PCT	$200	Switch	$200
Small C&I	PCT	$350	Switch	$350
Medium C&I	PCT	$1,050	Auto-DR	$1,050
Large C&I	Auto-DR[14]	$13,500	Not Applicable	Not Applicable

The analysis also estimated the cost benefit compared to the avoided cost of a gas-fired combustion turbine-generator. The assessment assumed that a demand response option with enabling technology is cost effective if the benefit-cost ration was one or higher. The larger the number, the greater the economic benefit. For Missouri, the results were as shown below:

[14] Auto-DR is a communications infrastructure to provide DR program participants electronic, internet-based price and reliability signals that are linked to the facility energy management control systems (EMCS) or related building and automated process control systems.

Table 7-11
Benefit Cost Ratio for Missouri DR Programs (from FERC 2009b,Tables D-16 and D-17)

Customer Type	Dynamic Pricing with Enabling Technology	Direct Load Control
Residential	1.24	4.18
Small C&I	1.27	4.78
Medium C&I	3.41	4.78
Large C&I	2.21	Not Applicable

7.16 References

FERC, “National Demand Response Potential Model Guide,” 2009a, pp. 1-31.

Ferc, “A National Assessment of Demand Response Potential,” 2009b, pp. 1-254.