GDS Associates, Inc.
ENGINEERS & CONSULTANTS

AMEREN MISSOURI

Demand-Side Management Market Potential Study

Prepared for:

Ameren Missouri

Final Report

December 30, 2016

www.gdsassociates.com

DEMAND-SIDE MANAGEMENT MARKET POTENTIAL STUDY

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Prepared By

GDS Associates, Inc. ENGINEERS & CONSULTANTS

In Partnership With

EMI CONSULTING

GDS Associates, Inc. | 1850 Parkway Place | Suite 800 | Marietta, GA 30067
770-425-8100 | Fax 770-426-0303 | www.gdsassociates.com
Marietta, GA • Austin, TX • Auburn, AL • Madison, WI • Manchester, NH • Orlando, FL • Hallowell, ME

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AEO	Annual Energy Outlook
BAU	Business as Usual
CAC	Central Air Conditioner
CBECS	Commercial Building Energy Consumption Survey
CFL	Compact Fluorescent Light
CHP	Combined Heat and Power
C&I	Commercial and Industrial
CP	Coincident Peak
DG	Distributed Generation
DLC	Direct Load Control
DR	Demand Response
DSM	Demand Side Management
EE	Energy Efficiency
EIA	Energy Information Administration
EM&V	Efficiency Measurement and Verification
EUI	Energy Use Intensity
IRP	Integrated Resource Plan
MEEIA	Missouri Energy Efficiency Investment Act
NTG	Net-to-Gross
NTGR	Net-to-Gross Ratio
RECS	Residential Energy Consumption Survey
RSPV	Rooftop Solar Photovoltaics
SAE	Statistically Adjusted End-Use
SEER	Seasonal Energy Efficiency Ratio
TOU	Time of Use
TRC	Total Resource Cost
UCT	Utility Cost Test
WACC	Weighted Average Cost of Capital

1 EXECUTIVE SUMMARY

1.1 BACKGROUND

This potential study provides a roadmap for both policy makers and Ameren Missouri as they develop strategies and programs for energy efficiency (EE), demand response (DR), distributed generation (DG) and combined heat and power (CHP) in the Ameren Missouri service area.[1] In addition to technical and economic potential estimates, the development of achievable and program potential estimates for a range of feasible measures is useful for program planning and modification purposes. Unlike achievable and program potential estimates, technical and economic potential estimates do not include customer acceptance considerations for measures, which are often among the most important factors when estimating the likely customer response to new programs. For this study, GDS Associates, Inc. ("GDS"), the consulting firm retained to conduct this study, produced the following estimates of demand side management potential:

- Technical potential
- Economic potential
- Achievable potential
    - Maximum achievable potential
    - Realistically achievable potential
- Program potential
    - Maximum achievable potential
    - Realistically achievable potential

For each level of potential, this detailed report presents the energy savings, peak demand savings, benefits and costs for the Ameren Missouri service area for the period of 2019-2036, an 18-year time frame.

1.2 MARKET RESEARCH

GDS subcontracted with EMI Consulting ("EMI") to review and update the market research content provided in EnerNOC Utility Solutions Consulting's *Demand-Side Management Market Potential Study, Volume 2: Market Research* published December 20, 2013 ("2013 Study"). The market research task consisted of a comprehensive review and analysis of all relevant existing data (primary and secondary) without the development of new data generated through primary research with Ameren customers—the method used in previous studies. The resulting approach combined multiple analytical methods and datasets including Ameren Missouri actual EE program implementation results as well as the implementation results of peer utilities.

1.2.1 Study Approach

At the onset of the project, it was expressed by Ameren Missouri and its stakeholders, that the market research approach should:

- Leverage existing data from Ameren Missouri on the results of three years of energy efficiency program implementation (2013, 2014, 2015).
- Rely upon secondary research and analysis rather than primary data collection and survey research

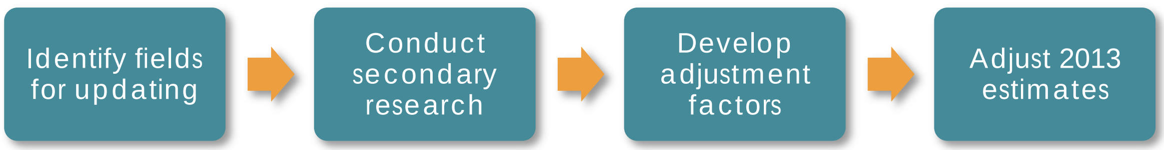
[1] Ameren Missouri notes that uncertainty exists at the time this document was prepared about the degree to which Combined Heat and Power projects fit within MEEIA's definitions of energy efficiency or demand response and how the costs and benefits should be evaluated. Regardless whether CHP fits into MEEIA's energy efficiency or demand response categories, the Company's potential study is a study of the future potential of demand-side measures that can be evaluated further as resource options as part of the Company's integrated resource plan.

with Ameren Missouri customers.

- [2]Consider the energy efficiency program implementation results of leading utilities with similar customers and characteristics.

The overall approach followed four steps depicted in Figure 1-1 below and described in the subsequent sections.

Figure 1-1// Overall Research Approach



1.3 BASE LOAD FORECAST

Ameren employs a sophisticated load forecasting system that uses econometric and Statistically Adjusted End-Use (SAE) models to project the number of consumers, average consumption per consumer, and total energy sales by class. The number of Residential, Commercial, and Industrial consumers are projected using traditional econometric techniques. Residential average electricity usage and commercial energy sales are projected using SAE model specifications. Industrial energy sales are projected using econometric techniques. SAE models are a hybrid forecasting tool, blending the strengths of end-use engineering models with econometric techniques. SAE models are employed by many utilities, including investor-owned utilities, electric cooperatives and municipal utilities. The models have withstood regulatory scrutiny for over a decade.

Two different baseline load forecasts will be used for the development of savings potential in the Study: the Naturally Occurring Forecast and the Business As Usual (BAU) Forecast:

- **Naturally Occurring Forecast** - The Naturally Occurring Forecast represents energy and demand sales projections with current codes and standards (projected or possible changes in codes and standards are not contemplated), with naturally occurring efficiency impacts included, and with savings from current DSM[3] programs included. Naturally occurring efficiency represents reductions in energy sales due to the fact that some proportion of consumers and businesses purchase and install equipment that is more efficient than minimums defined in current codes and standards and independent of formal DSM programs. Potential savings measured against the Naturally Occurring Forecast represent net savings.
- **BAU Forecast** - The BAU Forecast is similar to the Naturally Occurring forecast but with one difference. Like the Naturally Occurring forecast, the BAU forecast includes current codes and standards and includes current DSM program impacts. However, the BAU forecast excludes impacts associated with naturally occurring efficiency. Potential savings measured against the BAU Forecast represent gross savings.

[2] 4 CSR 240-22.050(3)(A)

[3] For ease of discussion, current DSM will be used throughout to include pre-MEEIA programs and MEEIA Cycle 1 and MEEIA Cycle 2 programs.

Table 1-1, Figure 1-2 and Figure 1-3 below provides the Naturally Occurring and BAU forecasts at the total system level for energy sales and Ameren system peak demand. Class break-downs are provided in Chapter 5.5 of this report. The methodologies employed by GDS to produce the Naturally Occurring and BAU Baseline forecasts are provided in detail in Chapter 5.4.4 of this report.

Table 1-1// Electric Energy Sales and Peak Demand Baseline Forecasts

	Naturally Occurring Baseline		Business as Usual Baseline	
Year	Energy Sales (MWh)	Demand (MW)	Energy Sales (MWh)	Demand (MW)
2017	31,408,545	6,930	31,610,707	6,976
2018	31,430,412	6,933	31,675,629	6,988
2019	31,443,602	6,932	31,728,806	6,995
2020	31,580,189	6,959	31,895,481	7,028
2021	31,554,959	6,950	31,901,927	7,024
2022	31,636,121	6,968	32,015,143	7,048
2023	31,807,334	7,004	32,217,937	7,090
2024	32,084,510	7,071	32,524,572	7,163
2025	32,126,152	7,083	32,596,360	7,181
2026	32,369,547	7,135	32,868,611	7,240
2027	32,556,029	7,179	33,081,835	7,288
2028	32,880,106	7,253	33,431,061	7,368
2029	33,152,022	7,312	33,726,486	7,431
2030	33,409,859	7,368	34,010,869	7,493
2031	33,630,970	7,420	34,257,237	7,549
2032	33,890,366	7,481	34,540,478	7,615
2033	33,996,419	7,508	34,669,318	7,647
2034	34,122,453	7,539	34,817,575	7,682
2035	34,266,011	7,575	34,981,970	7,723
2036	34,409,569	7,611	35,145,184	7,763

Figure 1-2// Total System Electric Energy Sales Baseline Forecasts

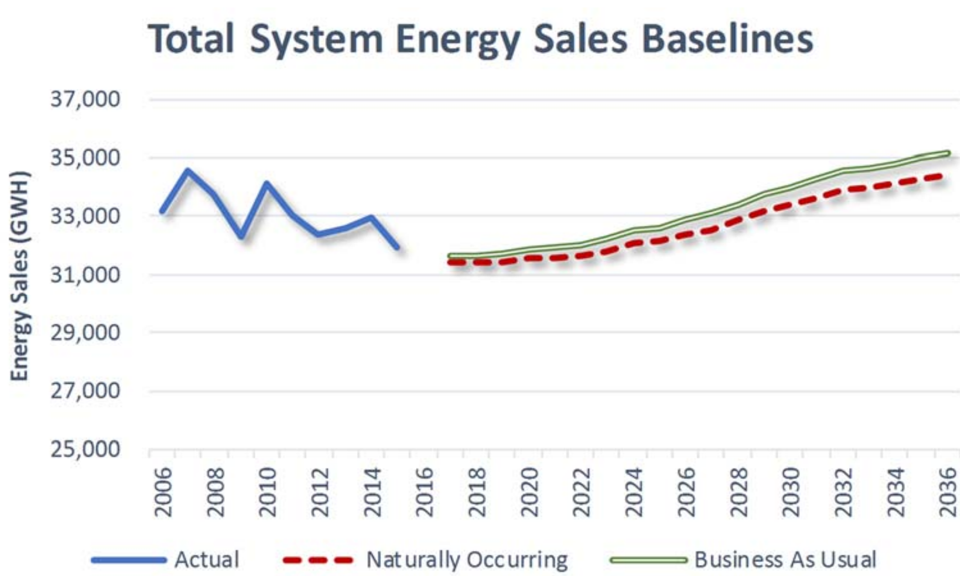
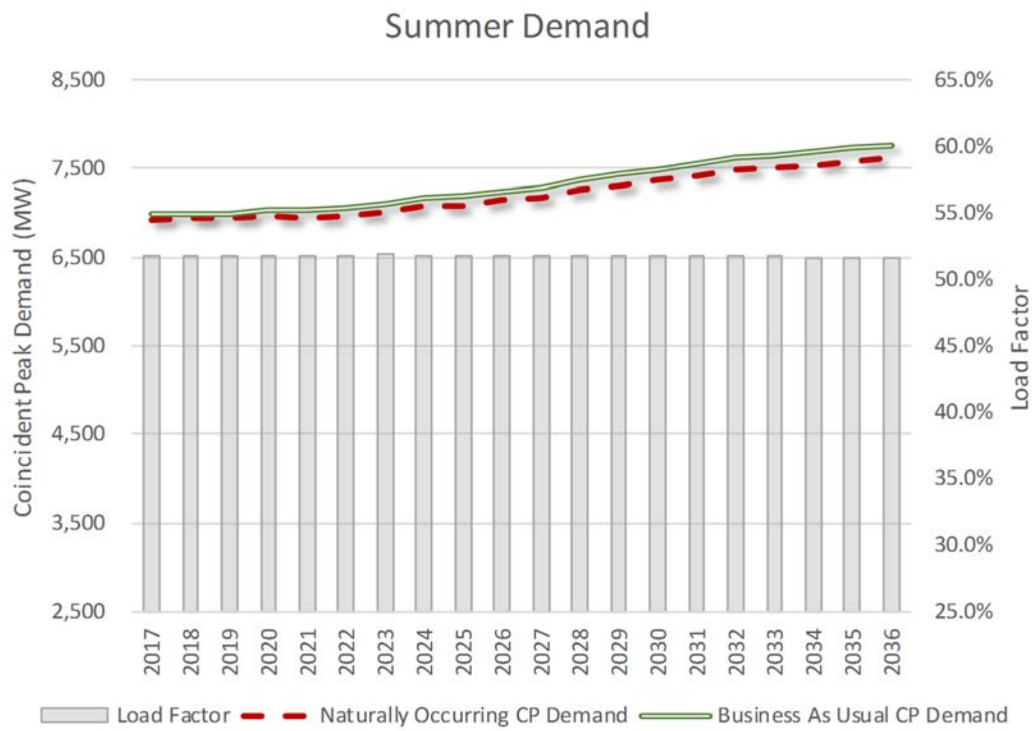


Figure 1-3// Total System Peak Demand Baseline Forecasts



1.4 ENERGY EFFICIENCY

The purpose of this energy efficiency potential study is to provide a foundation for the continuation of utility-administered energy efficiency programs in the Ameren Missouri service area and to determine the remaining opportunities for cost-effective energy efficiency savings for the Ameren Missouri service area. This study has examined a full array of energy efficiency technologies and energy efficient building practices that are technically achievable.

Efficient energy use, often referred to as energy efficiency, is using less energy to provide the same level of energy service. An example would be insulating a home or business to use less heating and cooling energy to achieve the same temperature. Another example would be installing LED lighting in place of incandescent, halogen, or fluorescent lighting to attain the same level of illumination. In general, energy efficiency is achievable primarily through more efficient technologies and/or processes rather than by changes in individual behavior.

1.4.1 Study Approach

GDS used a bottom-up approach to estimate energy efficiency potential in the residential sector. Bottom-up approaches begin with characterizing the eligible equipment stock, estimating savings and screening for cost-effectiveness first at the measure level, then summing savings at the end-use and service area levels. In the commercial and industrial sectors, the GDS team utilized a top-down modeling approach to first estimate measure-level savings and costs as well as cost-effectiveness, and then applied cost-effective measure savings to all applicable shares of electric energy load.

1.4.2 Summary of Results

Table 1-2 and Table 1-3 show the energy efficiency results for technical, economic, achievable, and program potentials. The cost-effective economic potential ranges from 23.5% to 31.7% across the 3-year and 18-year timeframes. The program RAP is 2.7% (~850,000 MWh and 150 MW) in the first three years of the study, growing to 12.5% across the 18-year timeframe. These percentages are calculated as the cumulative annual savings relative to the load forecast for the given year of the study timeframe.

Table 1-2// Summary of Cumulative Annual Energy Efficiency Energy Savings

	2019	2020	2021	2028	2036
Energy Savings (MWh)					
Technical	8,730,820	9,370,599	9,768,144	12,723,396	14,347,026
Economic	6,703,667	7,219,857	7,499,412	9,828,748	11,133,329
MAP	592,947	1,160,987	1,580,917	4,491,981	6,015,579
RAP	249,603	610,452	971,348	3,347,068	4,669,994
Program MAP	536,931	1,050,014	1,430,637	4,173,376	5,697,800
Program RAP	219,337	534,733	849,945	3,063,628	4,405,575
Energy Forecast	31,728,806	31,895,481	31,901,927	33,431,061	35,145,184
Savings (% of Total Forecasted Sales)					
Technical	27.5%	29.4%	30.6%	38.1%	40.8%
Economic	21.1%	22.6%	23.5%	29.4%	31.7%
MAP	1.9%	3.6%	5.0%	13.4%	17.1%
RAP	0.8%	1.9%	3.0%	10.0%	13.3%
Program MAP	1.7%	3.3%	4.5%	12.5%	16.2%
Program RAP	0.7%	1.7%	2.7%	9.2%	12.5%

Table 1-3// Summary of Cumulative Annual Energy Efficiency Demand Savings

	2019	2020	2021	2028	2036
Peak Demand Savings (MW)					
Technical	1,497	1,623	1,724	2,247	2,480
Economic	1,252	1,349	1,423	1,830	2,008
MAP	117	226	311	815	1,085
RAP	49	116	185	583	799
Program MAP	100	193	263	724	982
Program RAP	41	96	150	499	711
System Peak Forecast	6,995	7,028	7,024	7,368	7,763
Savings (% of System Peak)					
Technical	21.4%	23.1%	24.5%	30.5%	31.9%
Economic	17.9%	19.2%	20.3%	24.8%	25.9%
MAP	1.7%	3.2%	4.4%	11.1%	14.0%
RAP	0.7%	1.7%	2.6%	7.9%	10.3%
Program MAP	1.4%	2.7%	3.8%	9.8%	12.6%
Program RAP	0.6%	1.4%	2.1%	6.8%	9.2%

Table 1-4 shows the Total Resource Cost (TRC) test cost-effectiveness results for all cost effective programs for the Program MAP and Program RAP scenarios. These summaries are based on the 18-year timeframe of the study.

Table 1-4// Summary of Cost-Effectiveness of Energy Efficiency Program Measures ($, in millions)

	NPV Lifetime Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
Program MAP	$5,483	$2,887	$2,595	1.90
Program RAP	$4,128	$2,027	$2,101	2.04

1.5 BEHAVIORAL PROGRAMS

GDS conducted an analysis of the technical, economic, maximum achievable, and realistic achievable, potential for behavior programs and measures. This section of the executive summary provides an overview of the type of behavioral potential analyzed in the study, provides a brief overview of behavioral program efforts in the Ameren Missouri territory to date, and summarizes the results of our analysis.

1.5.1 Study Approach

Behavioral measures are typically defined as feedback programs, namely those that use energy usage information to prompt customers to take action. Feedback programs can be grouped into two general categories: indirect or asynchronous programs, and direct or real-time energy data programs.

The study analyzed measures in the residential and commercial sectors. For the residential sector, there were two principle measures: home energy reports and home energy monitors. Home energy monitors did not pass the cost-effectiveness screening for the residential sector. In some cases, home energy reports do pass the cost-effectiveness screening. For the commercial sector, there were three principle measures: commercial building energy reports, whole-building energy monitoring, and in-building energy use displays.

1.5.2 Summary of Results

Table 1-5 and Table 1-6 show the results for technical, economic, achievable, and program energy efficiency and demand reduction potentials for behavioral measures. Table 1-7 provides a summary of the cost effectiveness for these programs.

Table 1-5// Summary of Cumulative Annual Behavioral Program Energy Savings

	2019	2020	2021	2028	2036
Incremental Annual Energy Savings (MWh)					
Technical	434,564	471,419	508,251	582,543	583,580
Economic	366,479	366,479	366,479	366,479	366,479
MAP	204,553	253,672	253,672	253,672	253,672
RAP	150,460	173,672	184,908	189,155	189,155
Program MAP	200,693	246,651	245,751	235,897	230,398
Program RAP	84,433	106,521	136,093	175,645	170,122
Energy Forecast	31,728,806	31,895,481	31,901,927	33,431,061	35,145,184
Savings (% of Forecasted Sales)					
Technical	1.4%	1.5%	1.6%	1.7%	1.7%
Economic	1.2%	1.1%	1.1%	1.1%	1.0%
MAP	0.6%	0.8%	0.8%	0.8%	0.7%
RAP	0.5%	0.5%	0.6%	0.6%	0.5%
Program MAP	0.6%	0.8%	0.8%	0.7%	0.7%
Program RAP	0.3%	0.3%	0.4%	0.5%	0.5%

Table 1-6// Summary of Cumulative Annual Behavioral Program Demand Savings

	2019	2020	2021	2028	2036
Peak Demand Savings (MW)					
Technical	47	52	56	64	64
Economic	40	40	40	40	40
MAP	23	29	29	29	29
RAP	17	20	21	22	22
Program MAP	23	29	29	28	28
Program RAP	10	13	16	21	21
System Peak Forecast	6,995	7,028	7,024	7,368	7,763
Savings (% of System Peak)					
Technical	0.68%	0.73%	0.79%	0.87%	0.83%
Economic	0.57%	0.57%	0.57%	0.54%	0.51%
MAP	0.33%	0.41%	0.41%	0.39%	0.37%
RAP	0.25%	0.28%	0.30%	0.29%	0.28%
Program MAP	0.33%	0.41%	0.41%	0.38%	0.36%
Program RAP	0.14%	0.18%	0.23%	0.29%	0.27%

Table 1-7// Summary of Cost-Effectiveness of Behavioral Program Measures ($, in millions)

	NPV Lifetime Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
Program MAP	$229.4	$68.1	$161.3	3.4
Program RAP	$160.4	$54.0	$106.4	3.0

1.6 DEMAND RESPONSE

Demand response is defined as changes in electric usage by retail customers from their normal consumption patterns in response to changes in the price of electricity over various time periods, or to incentive payments designed to induce lower electricity use at times of peak electric demand. GDS used a systematic, bottom-up approach (at the customer segment and end use level) to develop estimates of DR potential for both the residential and non-residential (commercial and industrial) sectors.

1.6.1 Study Approach

The DR potential results were developed using customized versions of the GDS DR potential model (GDS DR Model) for the residential and non-residential sectors, and Ameren Missouri cost-effectiveness criteria including the most recent electric avoided cost projections. Key model inputs such as per participant demand savings, demand response program take rates and program delivery costs were obtained from various sources including:[4]

1) Information provided by Ameren
2) Ameren Missouri's 2013 DR potential study
3) Baseline studies conducted by Ameren Missouri
4) U.S. Department of Energy, Energy Information Administration (EIA)
5) Federal Energy Regulatory Commission (FERC) – National DR Model, DR Survey Data and Annual DR Reports
6) California Public Utilities Commission - DR program evaluation filings
7) Demand Response research reports by Rocky Mountain Institute and other organizations
8) Other recent DR potential studies

The GDS DR model is a spreadsheet tool that allows the user to determine the achievable potential for a demand response program based on the following basic equation:

$$\text{Achievable DR Potential} = \text{Per Customer CP Load for Eligible Customer Segment or End Use} \times \text{Potentially Eligible Customers} \times \text{Eligible Customer Take Rate} \times \text{Percent CP Load Reduction Per Participant}$$

The DR model also allows the user the option of inputting an expected peak kW reduction value per participant instead of a percent savings factor.

It is assumed that steady state take rates for DR program options will be achieved in 5 years. The ramp up to steady state take rates follows an "S-shaped" diffusion curve, where the rate of participation accelerates over the first half of the 5-year period, and then slows over the second half. An inverse S-shaped diffusion curve is used to determine the rate at which customer's opt-out of default rate

[4] 4 CSR 240-22.050(4)(A)

options.

This potential study evaluated DR potential for two achievable potential scenarios:

1) **Base Case Scenario:** The Base Case scenario assumes that all cost-effective DR programs will be implemented by Ameren and load switches will be used to control central air conditioning. No utility spending caps are placed on the achievable potential for this scenario.

2) **Smart Thermostat Scenario:** The smart thermostat scenario also assumes that all cost-effective DR programs will be implemented, but in this scenario controllable smart thermostats (such as Nest or Ecobee) will be used to control central air conditioning. As in the Base Case, no spending caps are placed on the achievable potential for this scenario.

GDS considered the DR program options seen in Table 1-8.

Table 1-8// DR Program Options Considered for DR Potential Study

DR Program Option	Eligible Rate Classes
Direct Load Control	
1. Control of Central Air Conditioners with Load Control Switch	Residential, SGS
2. Control of Electric Water Heaters	Residential, SGS
3. Control of Room Air Conditioners	Residential, SGS
4. Electric Thermal Storage – Cooling	SGS, LGS, SPS
5. Control of Swimming Pool Pumps	Residential, SGS
6. Control of Commercial Lighting - On/Off, Dimming	SGS
7. Agricultural Irrigation Pump Control	SGS
8. Control of Air Conditioners with Controllable "Smart" Thermostats (i.e. Nest, Weatherbug)	Residential, SGS
9. Control of Smart Appliances	Residential
Rate Options	
10. Base Interruptible Program	LGS, SPS
11. Time of Use Rate with and without Enabling Technology	Residential, SGS
12. Critical Peak Pricing Rate with and without Enabling Technology	Residential, SGS, LGS, SPS
13. Charging of Golf Carts Off Peak	SGS
14. Charging of Plug-In Utility Vehicles-Off Peak	SGS, LGS, SPS
15. Electric Vehicle Charging Station Off Peak (Personal and Fleet)	Residential, SGS
16. Inclining Block Rates	Residential
Aggregator Programs	
17. Capacity Bidding Programs	LGS, SPS, LPS
18. Demand Bidding Programs	SGS

1.6.2 Summary of Results

Table 1-9 shows the estimated MW demand savings for all applicable demand response programs, along with the savings as a percentage of the system peak. The cost-effective economic potential ranges from 26.9% to 41.7% across the 3-year and 18-year timeframes. The program RAP is 3.1% in the first three years of the study, growing to 6.2% across the 18-year timeframe. These percentages are calculated as the cumulative annual savings relative to the forecast for the given year of the timeframe.

Table 1-9// Summary of Cumulative Annual Base Case Demand Response Demand Savings

	2019	2020	2021	2028	2036
Peak Demand Savings (MW)					
Technical	2,353	2,394	2,403	3,676	3,713
Economic	1,631	1,784	1,887	3,205	3,237
MAP	272	366	440	1,064	1,082
RAP	20	93	223	537	549
Program MAP	268	355	422	947	927
Program RAP	20	92	218	492	482
System Peak Forecast	6,995	7,028	7,024	7,368	7,763
Savings (% of System Peak)					
Technical	33.6%	34.1%	34.2%	49.9%	47.8%
Economic	23.3%	25.4%	26.9%	43.5%	41.7%
MAP	3.9%	5.2%	6.3%	14.4%	13.9%
RAP	0.3%	1.3%	3.2%	7.3%	7.1%
Program MAP	3.8%	5.0%	6.0%	12.8%	11.9%
Program RAP	0.3%	1.3%	3.1%	6.7%	6.2%

Table 1-10 shows the cost-effectiveness screening results in each sector for MAP and RAP.

Table 1-10// Summary of Cost-Effectiveness Screening Results

DR Program Option	Sector	MAP Cost-Effectiveness	RAP Cost-Effectiveness
Critical Peak Pricing Rate with Enabling Technology	Residential	Yes	Yes
	Commercial	Yes	Yes
	Industrial	Yes	Yes
Critical Peak Pricing Rate without Enabling Technology	Residential	Yes	Yes
	Commercial	Yes	Yes
	Industrial	Yes	Yes
Time of Use Rate with Enabling Technology	Residential	No	No
	Commercial	No	No
	Industrial	No	No
Time of Use Rate without Enabling Technology	Residential	No	No
	Commercial	No	No
	Industrial	No	No

DR Program Option	Sector	MAP Cost-Effectiveness	RAP Cost-Effectiveness
Thermal Electric Storage- Cooling Rate	Commercial	No	No
	Industrial	No	No
Charging of Utility Vehicles Off Peak	Commercial	No	No
	Industrial	No	No
Charging of Golf Carts Off Peak	Commercial	No	No
Plug-In Electric Vehicle Charging Stations Off Peak	Residential	Yes	Yes
	Commercial	Yes	No
Interruptible Rate	Commercial	No	No
	Industrial	No	Yes
Inclining Block Rate	Residential	Yes	Yes
DLC Central AC- One-Way Switch	Residential	No	Yes
	Commercial	Yes	Yes
	Industrial	No	No
DLC AC - Smart Controllable Thermostats	Residential	No	Yes
	Commercial	No	No
	Industrial	No	No
DLC Lighting	Commercial	No	No
	Industrial	No	No
DLC Pool Pumps	Residential	No	No
	Commercial	No	No
DLC Room AC	Residential	No	No
	Commercial	No	No
	Industrial	No	No
DLC Agricultural Irrigation	Commercial	No	No
DLC Electric Water Heating	Residential	No	No
	Commercial	No	No
	Industrial	No	No
DLC Smart Appliances	Residential	No	No
Capacity Bidding	Commercial	Yes	Yes
	Industrial	Yes	Yes
Demand Bidding	Commercial	Yes	No
	Industrial	No	No

Table 1-11 shows the summary of DR Program cost-effectiveness for program MAP and program RAP.

Table 1-11// Summary of Cost-Effectiveness of Demand Response Program Measures ($, in millions) – Base Case

	NPV Lifetime Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
Program MAP	$1,411	$625	$786	2.26
Program RAP	$774	$346	$428	2.24

1.7 DISTRIBUTED GENERATION AND COMBINED HEAT AND POWER

Distributed generation generally refers to power generation at the point of consumption. DG includes the generation and storage of energy by small, grid-connected devices. GDS analyzed the remaining potential for one type of distributed generation resource in the Ameren Missouri service area: customer-sited solar photovoltaic systems.

On-site solar PV refers to rooftop PV systems that use solar energy to generate electricity. Similarly, the customer-sited wind projects included in this study are non-utility-scale sites that use wind energy to generate electricity.

Combined heat and power (CHP) units, which generate electricity and utilize waste heat for space or water heating requirements, can be used in buildings with fairly coincident thermal and electric loads, or buildings producing combustible biomass or biogas. CHP units traditionally have been installed in hospitals, schools, and manufacturing facilities, but can be used across nearly all market segments (residential, commercial or industrial).

Analysis included the following types of CHP units:

- Reciprocating engines
- Combustion turbines
- Steam turbines
- Micro turbines
- Fuel cells
- Organic Rankine Cycle

1.7.1 Summary of Results

Table 1-12 and Table 1-13 shows the estimated energy and demand savings for all applicable distributed generation and combined heat and power programs, along with the savings as a percentage of the system peak. These percentages are calculated as the cumulative annual savings relative to the forecast for the given year of the study's timeframe.

Table 1-12 / / Summary of Cumulative Annual Distributed Generation and Combined Heat and Power Energy Savings

	2019	2020	2021	2028	2036
Energy Savings (MWh)					
Technical	17,892,287	17,914,697	17,921,698	18,065,321	18,206,220
Economic	16,965,637	16,973,209	16,982,967	17,071,266	17,197,488
MAP	361,209	722,417	1,083,626	3,612,086	6,501,754
RAP	257,455	514,910	772,364	2,574,548	4,634,186
Program MAP	112,050	224,099	384,234	1,505,175	2,786,250
Program RAP	0	0	338,408	1,240,224	2,270,870
Energy Forecast	31,728,806	31,895,481	31,901,927	33,431,061	35,145,184
Savings (% of Forecast Sales)					
Technical	56.39%	56.17%	56.18%	54.04%	51.80%
Economic	53.47%	53.22%	53.23%	51.06%	48.93%
MAP	1.14%	2.26%	3.40%	10.80%	18.50%
RAP	0.81%	1.61%	2.42%	7.70%	13.19%
Program MAP	0.35%	0.70%	1.20%	4.50%	7.93%

	2019	2020	2021	2028	2036
Program RAP	0.00%	0.00%	1.06%	3.71%	6.46%

Table 1-13// Summary of Cumulative Annual Distributed Generation and Combined Heat and Power Demand Savings

	2019	2020	2021	2028	2036
Peak Demand Savings (MW)					
Technical	2,687	2,690	2,691	2,711	2,729
Economic	2,563	2,564	2,565	2,577	2,594
MAP	41	83	124	413	743
RAP	21	42	63	209	376
Program MAP	3	6	17	91	176
Program RAP	3	6	12	59	111
System Peak Forecast	6,995	7,028	7,024	7,368	7,763
Savings (% of System Peak)					
Technical	38.42%	38.28%	38.31%	36.79%	35.16%
Economic	36.64%	36.48%	36.52%	34.98%	33.41%
MAP	0.59%	1.18%	1.76%	5.61%	9.58%
RAP	0.30%	0.60%	0.89%	2.84%	4.85%
Program MAP	0.05%	0.09%	0.24%	1.24%	2.27%
Program RAP	0.04%	0.08%	0.18%	0.79%	1.43%

Table 1-14 shows the summary of cost-effectiveness for program MAP and program RAP.

Table 1-14// Summary of Cost-Effectiveness of DG/CHP Program Measures ($, in millions)

	NPV Lifetime Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
Program MAP	$2,437	$1,786	$651	1.36
Program RAP	$1,883	$1,418	$465	1.33

1.8 COMBINED RESULTS

Table 1-15 shows the combined Program MAP and Program RAP MWh savings, along with the savings as a percentage of the Ameren Missouri system peak. These values include the Energy Efficiency, Behavior, and Distributed Generation/Combined Heat and Power studies. There are no expected energy (MWh) savings from DR programs.

Table 1-15// Summary of Cumulative Annual Total Combined Energy Savings

	2019	2020	2021	2028	2036
Energy Savings (MWh)					
Program MAP	849,674	1,520,765	2,060,622	5,914,449	8,714,448
Program RAP	303,770	641,254	1,324,446	4,479,497	6,846,568

Sales Forecast	31,728,806	31,895,481	31,901,927	33,431,061	35,145,184
Savings (% of Energy Sales)					
Program MAP	2.68%	4.77%	6.46%	17.69%	24.80%
Program RAP	0.96%	2.01%	4.15%	13.40%	19.48%

Table 1-16 shows the combined program MAP and program RAP MW savings, along with the savings as a percentage of the system peak forecast. These values include all four studies: Energy Efficiency, Behavior, Demand Response, and Distributed Generation/ Combined Heat and Power.

Table 1-16// Summary of Cumulative Annual Total Combined Demand Savings

	2019	2020	2021	2028	2036
Peak Demand Savings (MW)					
Program MAP	395	583	732	1,790	2,113
Program RAP	74	206	396	1,071	1,325
System Peak Forecast	6,995	7,028	7,024	7,368	7,763
Savings (% of System Peak)					
Program MAP	5.6%	8.3%	10.4%	24.3%	27.2%
Program RAP	1.1%	2.9%	5.6%	14.5%	17.1%

Table 1-17 and Table 1-18 show the Program MAP and Program RAP net present values of the total benefits, costs, and net benefits, along with the TRC ratio for each study.

Table 1-17// Program MAP Cost-Effectiveness ($, in millions)

PP MAP	NPV Benefits	NPV Costs	Net Benefits	18-YR TRC Ratio
Energy Efficiency	$5,481.50	$2,887.34	$2,594.16	1.90
Behavioral	$229.38	$68.12	$161.26	3.37
Demand Response	$1,411.31	$625.26	$786.05	2.26
CHP/DG	$2,437.17	$1,786.41	$650.76	1.36
Total	**$9,559.36**	**$5,367.13**	**$4,192.23**	**1.78**

Table 1-18// Program RAP Cost-Effectiveness ($, in millions)

PP RAP	NPV Benefits	NPV Costs	Net Benefits	18-YR TRC Ratio
Energy Efficiency	$4,127.80	$2,026.98	$2,100.82	2.04
Behavioral	$168.90	$53.96	$114.94	3.13
Demand Response	$774.15	$346.33	$427.82	2.24

PP RAP	NPV Benefits	NPV Costs	Net Benefits	18-YR TRC Ratio
CHP/DG	$1,882.96	$1,417.62	$465.35	1.33
Total	**$6,953.81**	**$3,844.89**	**$3,108.92**	**1.81**

2 GLOSSARY OF TERMS

The following list defines many of the key terms used throughout this DSM market potential study and in the GDS DR Potential Model.

Achievable Potential: The November 2007 National Action Plan for Energy Efficiency "Guide for Conducting Energy Efficiency Potential Studies" defines achievable potential as the amount of energy use that energy efficiency can realistically be expected to displace assuming the most aggressive program scenario possible (*e.g.*, providing end-users with payments for the entire incremental cost of more efficient equipment). This is often referred to as maximum achievable potential. Achievable potential takes into account real-world barriers to convincing end-users to adopt efficiency measures, the non-measure costs of delivering programs (for administration, marketing, tracking systems, monitoring and evaluation, etc.), and the capability of programs and administrators to ramp up program activity over time.

Age of Existing Program: The number of years that the existing program being analyzed has been in operation.

Amortized Program Equipment Costs: The process of allocating the cost of an asset over the useful life of that asset.

Annual Number of Control Hours: The annual number of hours that a DR program or measure will reduce a participant's electrical demand.

Applicability Factor: The fraction of the applicable housing units or businesses that is technically feasible for conversion to the efficient technology from an engineering perspective (e.g., it may not be possible to install CFLs in all light sockets in a home because the CFLs may not fit in every socket in a home).

Avoided Costs: For purposes of this report, the electric avoided costs are defined as the generation, transmission and distribution costs that can be avoided in the future if the consumption of electricity can be reduced with energy efficiency or demand response programs.

Avoided Generation Cost per kW-Yr.: These are the generation capacity costs that are avoided due to the implementation of demand response.

Avoided Transmission & Distribution ($/kW-Yr.): These are the transmission and distribution infrastructure costs that are avoided due to the implementation of demand response.

Base Achievable Potential: For purposes of this study, an achievable potential scenario which assumes incentives are set to 50% of the incremental or full measure cost.

Base Case Equipment End-Use Intensity: The electricity used per customer per year by each base-case technology in each market segment. This is the consumption of the electric energy using equipment that the efficient technology replaces or affects. For example, if the efficient measure is a high efficiency light bulb (CFL), the base end-use intensity would be the annual kWh use per bulb per household associated with a halogen incandescent light bulb that provides equivalent lumens to the CFL.

Base Case Factor: The fraction of the market that is applicable for the efficient technology in a given market segment. For example, for the residential electric clothes washer measure, this would be the fraction of all residential customers that have an electric clothes washer in their household.

Base Participant CP Demand (kW): The total participant coincident (with the system peak) demand before any demand response reductions.

Base Sector CP Demand (kW): The total coincident (with the system peak) demand of all eligible customers before any demand response reductions.

Central Controller Hardware Cost: The cost of a central (utility) control system that is used to communicate with customer based control equipment such as switches. If the central controller is used by multiple programs, the costs should be split among these programs.

Central Controller Software Costs: The cost of central (utility) control system software that is used to communicate with customer based control equipment such as switches. If the central controller and its software are used by multiple programs, the software costs should be split among these programs.

Coincidence Factor: The fraction of connected load expected to be “on” and using electricity coincident with the electric system peak period.

Coincident Peak (CP) Load per Eligible Customer (kW): The participant coincident (with the system peak) demand per eligible customer before any demand response reductions.

Coincident Peak Demand Reduction (kW): The total coincident (with the system peak) demand reduction for all program participants.

Coincident Peak Demand Reduction @ Gen (kW): The total participant coincident (with the system peak) demand reduction, including line losses.

Combined Heat and Power (CHP): A system or integrated package of generating equipment that produces both electricity and heat onsite. For purposes of this study, all power and heat is excluded from being exported.

Commercial Sector: Comprised of non-manufacturing premises typically used to sell a product or provide a service, where electricity is consumed primarily for lighting, space cooling and heating, office equipment, refrigeration and other end uses. Business types are included in Section 5 – Methodology.

Control Equipment Useful Life (Years): The number of years that control equipment installed at the customer site is expected to operate before it needs to be replaced.

Cost-Effectiveness: A measure of the relevant economic effects resulting from the implementation of an energy efficiency measure or program. If the benefits are greater than the costs, the measure is said to be cost-effective.

Cost to Serve Energy during Control ($/MWh): The cost to meet customer energy requirements during peak demand periods.

Cost to Serve Energy during Recovery ($/MWh): The cost to meet customer energy requirements during off peak demand periods.

Cumulative Annual: Refers to the overall annual savings occurring in a given year from both new participants and annual savings continuing to result from past participation with energy efficiency measures that are still in place. Cumulative annual does not always equal the sum of all prior year incremental values as some energy efficiency measures have relatively short lives and, as a result, their savings drop off over time.

Demand Response: Refers to electric demand resources involving dynamic hourly load response to market conditions, such as curtailment or load control programs.

Demand Side Management (DSM): The design, implementation, and analysis of customer-focused energy and demand use reduction programs.

Distributed Generation (DG): A system or technology that produces energy onsite where it is located and either used onsite or exported to the electrical grid. For purposes of this study, all power generated is assumed to be exported to the electrical grid.

Dynamic Peak Pricing: Dynamic pricing generally refers to the family of rates that offer customers time-varying electricity prices on a day-ahead or real-time basis. The Dynamic Peak Pricing Rate currently offered by Ameren Missouri is a more static tiered TOU pricing rate that also includes a critical peak pricing component.

Direct Load Control (DLC): A demand response activity by which the program sponsor remotely shuts down or cycles a customer's electrical equipment (e.g., air conditioner, water heater) on short notice. Direct load control programs are primarily offered to residential or small commercial customers. Also known as direct control load management.

Discount Rate: An interest rate applied to a stream of future costs and/or monetized benefits to convert those values to a common period, typically the current or near-term year, to reflect the time value of money. It is used in benefit-cost analysis to determine the economic merits of proceeding with the proposed project, and in cost-effectiveness analysis to compare the value of projects. The discount rate for any analysis is either a nominal discount rate or a real discount rate. A Nominal Discount Rate is used in analytic situations when the values are in then-current or nominal dollars (reflecting anticipated inflation rates).

Early Replacement: Refers to an energy efficiency measure or efficiency program that seeks to encourage the replacement of functional equipment before the end of its operating life with higher-efficiency units.

Economic Potential: The November 2007 National Action Plan for Energy Efficiency "Guide for Conducting Energy Efficiency Potential Studies" refers to the subset of the technical potential that is economically cost-effective as compared to conventional supply-side energy resources as economic potential. Both technical and economic potential ignore market barriers to ensuring actual implementation of efficiency. Finally, they only consider the costs of efficiency measures themselves, ignoring any programmatic costs (e.g., marketing, analysis, administration, evaluation) that would be necessary to capture them.

Eligible Customers: The total number of customers that are eligible to participate in a demand response program.

End-Use: A category of equipment or service that consumes energy (*e.g.*, lighting, refrigeration, heating, process heat, cooling).

Energy Efficiency: Using less energy to provide the same or an improved level of service to the energy consumer in an economically efficient way. Sometimes "conservation" is used as a synonym, but that term is usually taken to mean using less of a resource even if this results in a lower service level (*e.g.*, setting a thermostat lower or reducing lighting levels).

Energy Use Intensity (EUI): A unit of measurement that describes a building's energy use. EUI represents the energy consumed by a building relative to its size.[5]

Firm Load Reduction: Load reduction associated with a direct load control program with no customer override option.

Free Driver: Individuals or businesses that adopt an energy efficient product or service because of an energy efficiency program, but are difficult to identify either because they do not receive an incentive or are not aware of the program.

Free Rider: Participants in an energy efficiency program who would have adopted an energy efficiency technology or improvement in the absence of a program or financial incentive.

[5] See http://www.energystar.gov/index.cfm?fuseaction=buildingcontest.eui

Gross Savings: Gross energy (or demand) savings are the change in energy consumption or demand that results directly from program-promoted actions (e.g., installing energy-efficient lighting) taken by program participants regardless of the extent or nature of program influence on their actions.

Hierarchy Ranking: A ranking of DR programs (where 1 is the highest rank) that determines the order in which the same pool of eligible customers is allowed to participate in DR programs that are considered to interact with one another. The purpose of the hierarchy ranking is to avoid double counting of potential demand reductions.

Implementation, Admin, Marketing: Direct utility or energy efficiency organization costs to market, promote, operate, and manage the program.

Incentive Costs: A rebate or some form of payment used to encourage electricity consumers to implement a given demand-side management (DSM) technology.

Incremental: Savings or costs in a given year associated only with new installations of energy efficiency or demand response measures happening in that specific year.

Industrial Sector: Comprised of manufacturing premises typically used for producing and processing goods, where electricity is consumed primarily for operating motors, process cooling and heating, and space heating, ventilation, and air conditioning (HVAC). Applicable business types are included in section 5 – Methodology.

Installation Cost per Unit – Equipment: The cost of equipment, such as a control switch, that is required at the customer site for participation in the program.

Installation Cost per Unit – Labor: The cost of labor associated with the installation of equipment, such as a control switch, that is required at the customer site for participation in the program.

Integrated Resource Plan (IRP): A comprehensive planning document developed by a utility, designed to incorporate the most cost effective supply side and demand side resources, and intended to serve as a framework for long-term utility operations.

Load Shifting Program: A demand response program that shifts a portion of customer load from on-peak to off peak hours.

Maximum (or Max) Achievable: An achievable potential scenario which assumes incentives for program participants are equal to 100% of measure incremental or full costs.

Max Customer Participation Rate: The expected customer participation rate at the end of the study period.

Measure: Any action taken to increase energy efficiency or demand response, whether through changes in equipment, changes to a building shell, implementation of control strategies, or changes in consumer behavior. Examples are higher-efficiency central air conditioners, occupancy sensor control of lighting, and retro-commissioning. In some cases, bundles of technologies or practices may be modeled as single measures. For example, an ENERGY STAR® ™ home package may be treated as a single measure.

Missouri Energy Efficiency Investment Act (MEEIA): A Missouri state law passed by way of Senate Bill 376 in 2009 that provides the framework for investor owner utilities to create and implement demand side management programs. The statute reference is RSMo, Section 393.1075.

MMBtu: A measure of power, used in this report to refer to consumption and savings associated with natural gas consuming equipment. One British thermal unit (symbol Btu or sometimes BTU) is a traditional unit of energy equal to about 1055 joules. It is the amount of energy needed to heat one pound of water by one degree Fahrenheit. MMBtu is defined as one million BTUs.

MW: A unit of electrical output, equal to one million watts or one thousand kilowatts. It is typically used to refer to the output of a power plant.

MWh: One thousand kilowatt-hours, or one million watt-hours. One MWh is equal to the use of 1,000,000 watts of power in one hour.

Net-to-Gross Ratio: A factor representing net program savings divided by gross program savings that is applied to gross program impacts to convert them into net program load impacts

Net Savings: Net energy or demand savings refer to the portion of gross savings that is attributable to the program. This involves separating out the impacts that are a result of other influences, such as consumer self-motivation. Given the range of influences on consumers' energy consumption, attributing changes to one cause (i.e., a particular program) or another can be quite complex.

Non Incentive Cost: Costs incurred by the utility that do not include incentives paid to the customer (i.e.: program administrative costs, program marketing costs, data tracking and reporting, program evaluation, etc.)

Nonparticipant Spillover: Savings from efficiency projects implemented by those who did not directly participate in a program, but which nonetheless occurred due to the influence of the program.

Number of Control Units Per Participant: The number of control switches that are required for each program participant.

Participant Cost: The cost to the participant to participate in an energy efficiency program.

Participant Incentive ($/kW-Yr.): Incentives paid to program participants stated as $/kW-Yr.

Participant Spillover: Additional energy efficiency actions taken by program participants as a result of program influence, but actions that go beyond those directly subsidized or required by the program.[6]

Peak Demand Line Loss Factor: Percentage of electric energy lost because of the transmission of electricity.

Per Participant CP Reduction (kW): The per participant coincident (with the system peak) demand reduction that will result from participation in the DR program.

Program Participation Rate: Percent of total eligible market for the DR measure that will participate in the DR program in each year. For example, if the program is residential central AC load control, the program participation rate would be the number of program participants/the number of residential customers with central AC.

Program Savings Factor (Percent of CP Load): The percentage reduction in the participant coincident (with the system peak) demand due to participation in the DR program.

Rate of General Inflation: The periodic rate at which general consumer prices increase. The General Inflation Rate is normally determined as an historical trend, using the Consumer Price Index (CPI) as published by the U.S. Bureau of Labor Statistics.

Reserve Margin: The difference between the dependable capacity of a utility's system and the anticipated peak load for a specified period.

Rooftop Solar Photovoltaics (RSPV): For purposes of this study, stationary mounted rooftop solar panels, connected to a standard inverter and interconnected to the utility grid.

Saturation Percentage of Targeted End Use: The percentage of eligible customers that have the

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[6] The definitions of participant and nonparticipant spillover were obtained from the National Action Plan for Energy Efficiency Report titled "Model Energy Efficiency Program Impact Evaluation Guide", November 2007, page ES-4.

end use that will be controlled by the DR program.

Start of Slow Growth (Year #): The year on the market adoption curve that slow growth in customer participation will begin.

Statistically Adjusted End-Use (SAE) Model: An economic forecasting model used to project number of consumers, average consumption per consumer, and total energy sales by customer class.

Take Rate: The percentage of customers in a market segment, usually of a particular customer class, that are expected to adopt a certain measure or program.

Technical Potential: The theoretical maximum amount of energy use that could be displaced by energy efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end-users to adopt the energy efficiency measures

Time of Use Rate: A rate where usage unit prices vary by time period, and where the time periods are typically longer than one hour within a 24-hour day. Time-of-use rates reflect the average cost of generating and delivering power during those time periods.

Total Resource Cost Test (TRC Test): The Total Resource Cost Test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs. The benefits calculated in the Total Resource Cost Test are the avoided supply costs, the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost for the periods when there is a load reduction.

Units Replaced at End of Useful Life: The number of units (such as control switches) that will need to be replaced at the end of their useful life.

Utility Cost Test (UCT): The utility cost test, also known as the program administrator cost test, examines the costs and benefits of the energy efficiency or demand response program from the perspective of the entity implementing the program (utility, government agency, nonprofit, or other third party). The costs included in the UCT include overhead and incentive costs. Overhead costs are administration, marketing, research and development, evaluation, and measurement and verification. Incentive costs are payments made to the customers to offset purchase or installations costs. The benefits from the utility perspective are the savings derived from not delivering the energy to customers. Depending on the jurisdiction and type of utility, the “avoided costs” can include reduced wholesale electricity or natural gas purchases, generation costs, power plant construction, transmission and distribution facilities, ancillary service and system operating costs, and other components.

Variable Program Equipment Costs: Program equipment costs, such as the cost of control switches that vary with the number of program participants.

Weighted Average Cost of Capital (WACC): The weighted average cost of capital (WACC) is the rate that a company is expected to pay on average to all its debt and equity holders to finance its assets.

3 INTRODUCTION

3.1 BACKGROUND

Ameren Missouri contracted with GDS Associates (GDS) and project partner EMI Consulting for the purpose of preparing an independent evaluation of the market potential for electrical energy efficiency (EE), demand response (DR), and distributed generation/combined heat and power (DG/CHP) in the Ameren Missouri service area for the period 2019 to 2036. This Demand Side Management Market Potential Study ("DSM Potential Study") used updated baseline estimates based on the latest information pertaining to federal, state, and local codes and standards for improving energy efficiency. The study also quantifies and includes estimates of naturally occurring energy efficiency in the baseline forecast.

Ameren Missouri will use the results of this DSM Potential Study in its integrated resource planning process to analyze various levels of DSM related savings and peak demand reductions attributable to energy efficiency, demand response (DR) and DG/CHP initiatives at various levels of cost over the planning horizon from 2019 to 2036. Ameren Missouri's resource planning schedule required an accelerated schedule for completing this study and a reduced scope of work relative to Ameren Missouri's two prior DSM Potential Studies. To accommodate the accelerated schedule, it was decided that no additional primary market research would be conducted. Instead, the GDS Team used the prior Ameren Missouri primary market research conducted for its 2013 DSM Potential Study and Ameren Missouri's 2013-2015 DSM Program impact and process evaluation results, whenever possible. Estimates of customer participation rates in future Ameren Missouri DSM programs (take rates) from the 2013 study were updated based on EM&V results of actual customer participation from prior Ameren energy efficiency programs as well as those of other leading utility programs with similar customer and energy efficiency characteristics.

The key objectives of this study include:

- Conduct an 18-year EE potential study to determine the potential for specific energy efficiency measures to reduce the consumption and peak demand of electricity in the Ameren Missouri service area.
- Conduct an 18-year DR potential study to determine the potential for reduction in peak demand through demand response programs in the Ameren Missouri service area.
- Conduct an 18-year DG/CHP potential study to determine the resource potential for DG/CHP resources in the Ameren Missouri service area.
- Compare the results of this study to the prior 2013 DSM Potential Study.

3.2 DEFINITIONS OF DEMAND SIDE MANAGEMENT POTENTIAL

DSM potential is typically grouped into the following three types of potential: technical potential, economic potential, and achievable potential. An additional type of DSM potential estimate, program potential, was also included in this study. These are the types of DSM potential that were identified in this study for EE, DR and DG/CHP. Technical and economic potential are both theoretical potential limits, while achievable potential includes assumptions about the decisions customers make regarding equipment efficiency, maintenance activities, control of energy-consuming equipment, elements of new building construction, if and how they generate electricity, and how alternative rate structures can fit their business operations or personal lifestyle. For this reason, we developed a range of achievable potential estimates and also conducted sensitivity analysis around program potential.

Each of the types of DSM potential included in this study are described below. Any definitional differences that might exist for different types of DSM are addressed in report sections that present the potential results for each type of DSM (EE, DR and DG/CHP).

Technical Potential: For this study, the GDS Team determined the technical potential for energy efficiency, demand response and DG/CHP. In accordance with the Missouri rules, as stated in 4 CSR 240-22.020(40), (49), and (59), *"technical potential means energy savings and demand savings relative to a utility's baseline energy forecast and baseline demand forecast, respectively, resulting from a theoretical construct that assumes all feasible measures are adopted by customers of the utility regardless of cost or customer preference."*

Economic Potential: Economic potential refers to the subset of the technical potential that is economically cost-effective as compared to conventional supply-side energy resources. All measures that are not found to be cost-effective based on the results of the TRC test are excluded from estimates of economic potential.

Achievable Potential: Achievable potential is defined as the amount of energy use that can expect to be saved based on assumptions relating to funding levels, future code requirements and level of marketing efforts. Achievable potential takes into account barriers that hinder consumer adoption of energy efficiency measures such as financial, political and regulatory barriers, and the capability of programs and administrators to ramp up activity over time. The analysis reports both Maximum and Realistically Achievable potential.

Maximum Achievable Potential (MAP): This is generally defined as the maximum cost-effective potential that can practically be attained in a real-world program delivery scenario, assuming that incentives and take rates are at the high end of actual utility program offerings and results. Realistically Achievable Potential (RAP) generally represents an estimate of the amount of potential that can realistically be achieved given incentive levels consistent with MEEIA Cycle 1 and 2, and typical industry experience with similar program offerings.

Realistically Achievable Potential (RAP): This generally represents an estimate of the amount of potential that can realistically be achieved given incentive levels consistent with MEEIA Cycle 1 and 2, and typical industry experience with similar program offerings.

Program Potential: The GDS Team aggregated cost-effective measures into programs based on a mapping of cost-effective measures to existing Ameren Missouri programs or new programs, if necessary. Program potential includes the allocation and bundling of individual measures into specific program concepts to support Ameren Missouri's program planning process. Measures that are in the achievable potential but excluded from program potential include those for which the efficiency market has already largely transformed (televisions), measures which have shown to achieve poor realization rates or very low participation in other jurisdictions. Program potential also incorporates NTG considerations, and excludes measures with low NTG ratios. Program potential cases were created based on the RAP and MAP achievable potentials.

3.3 REPORT ORGANIZATION

The remainder of this report is organized as follows:

Section 4: Market Research discusses the existing datasets available to the GDS Team that were analyzed and updated based on available secondary information. The effort primarily consisted of updating the prior study take rates to reflect the latest available market research.

Section 5: Baseline Forecast details the various ways in which the load forecast for Ameren Missouri is used for other aspects of the study, presents the baseline and disaggregated forecasts, and describes the methodology and data sources used by GDS for the purposes of generating the forecasts that are used in the potential analysis.

Section 6: Energy Efficiency Potential provides a breakdown of the electric energy efficiency potential by customer sector, including cost-effectiveness and budget assumptions. This section includes a brief comparison of results to the prior potential analysis completed in 2013.

Section 7: Behavioral Programs Potential provides a breakdown of the potential from behavioral measures/programs for the residential and commercial sector.

Section 8: Demand Response Potential provides a breakdown of the demand response potential by customer sector and cost-effectiveness of both load control devices as well as rate-based DR.

Section 9: Distributed Generation/Combined Heat & Power Potential provides a breakdown of the CHP and Solar DG potential in the Ameren Missouri service territory.

Section 10: Combined Results presents the combined energy and summer peak demand potential for energy efficiency, behavior-based programs, demand response and DG/CHP. The combined potentials account for interactive effects across the various DSM potential.

Section 11: Sensitivity Analysis presents the results of sensitivity analyses on six key assumptions included in the potential study. These sensitivities include avoided costs, take rates, attribution, mandatory inclining block rate assumptions, accelerated smart meter deployment, and a more conservative estimate of low-income qualified housing population.

4 MARKET RESEARCH[7]

4.1 INTRODUCTION

One of the initial steps in the 2016 Demand-Side Management Market Potential Study was to identify which data fields can and should be updated to reflect the most recent known market conditions. As part of this scope, GDS and EMI Consulting were tasked with reviewing and updating (where possible) the market research content, with a focus on the measure take rate analysis, provided by EnerNOC Utility Solutions Consulting in the *Demand-Side Management Market Potential Study, Volume 2: Market Research* published December 20, 2013 ("2013 Study"). The market research task consisted of a comprehensive review and analysis of all relevant existing data (primary and secondary) without the development of new data generated through primary research with Ameren customers—the method used in previous studies. The resulting approach combined multiple analytical methods and datasets including Ameren Missouri actual energy efficiency ("EE") program implementation results, as well as the implementation results of peer utilities[8].

The following chapter describes the research approach and findings from updates to residential and non-residential take rates and low income market characteristics. The content in this chapter provides the results of the analysis in a concise format; for additional background material, please see the appendices.
The data from this analysis was used to inform the estimate of energy efficiency potential being developed as part of the larger study.

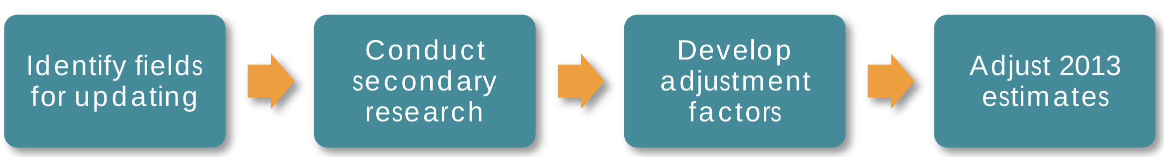
4.2 APPROACH[9]

At the onset of the project, it was expressed by Ameren Missouri and its stakeholders, that the market research approach should:

- Leverage existing data from Ameren Missouri on the results of three years of energy efficiency program implementation (2013, 2014, 2015).
- Rely upon secondary research and analysis rather than primary data collection and survey research with Ameren Missouri customers.
- Consider the energy efficiency program implementation results of leading utilities with similar customers and characteristics.

The overall approach followed four steps depicted in Figure 4-1 below and described in the subsequent sections.

Figure 4-1// Overall Research Approach



4.2.1 Identify Fields for Updating

In this step, the GDS Team reviewed the 2013 Study to understand the fields that can and should be

[7] 4 CSR 240-22.050(3)(B); 4 CSR 240-22.050(3)(C); 4 CSR 240-22.050(1)(A)
[8] 4 CSR 240-22.050(3)(A)
[9] 4 CSR 240-22.050(2)

updated using secondary sources. Table 4-1 below describes the data updated and reported on in this section of the report.

Table 4-1 // 2013 Data Selected for Updates[10]

Data	Update
Residential Take-Rates	Updated Appendix Table A1 from the 2013 Study
Business Take Rates	Updated Appendix Table D1 from the 2013 Study
Residential Psychographic Take Rates (or Take Rates by Market Segment)	Updated Table 6-3 from the 2013 Study
Business Psychographic Take Rates (or Take Rates by Market Segment)	Updated Table 9-4 from the 2013 Study

4.2.2 Conduct Secondary Research

The next step in the research process was to identify and review available data that could be used to make adjustments to the 2013 estimates. Data sources evaluated were:

- **Ameren Missouri Evaluation, Measurement and Verification Reports:** The GDS Team reviewed the EM&V reports developed by ADM, Research Into Action, Cadmus and Nexant for all Ameren Missouri business and residential programs implemented in years 2013, 2014 and 2015. The purpose of this review was to extract participation information and understand any important challenges, changes or results that might inform our understanding of the Ameren Missouri customer context. This review documented important elements of the program designs (e.g. incentive levels, equipment offered), as well as notable process and impact findings; for example, in the review, analysts documented highlights from the reports such as, the major barriers to implementing efficiency projects as reported through survey research with participants.
- **Ameren Missouri Energy Efficiency Program Implementation Data:** The GDS Team reviewed the actual energy efficiency program implementation results provided in an Excel file from Ameren Missouri staff. This review consisted of an analysis of both the Non-Residential and Residential data; specifically, implementation results from the 2013 – 2015 energy efficiency programs were analyzed to understand the number of unique accounts that participated by measure. The data was translated into the measure categories from the 2013 Study as a means for estimating the actual adoption of the 2013 Study measures and the market penetration by measure.
- **Peer Utility Energy Efficiency Program Reports:** The GDS Team sought out relevant measure level results from peer utilities[11]. This involved examining utility EM&V and annual reports, as well as leveraging E Source material tracked through their DSM Advisory service. The team was able to obtain relevant measure level customer participation benchmarks from the following utilities: Ameren Illinois, Arizona Public Service, Commonwealth Edison, Entergy Arkansas, Indianapolis Power & Light, MidAmerican, Puget Sound Energy, and Interstate Power & Light. The GDS Team sought out but was unable to obtain comparable benchmarks from the following utilities: Kansas City Power & Light, NIPSCO, Northern States, San Diego Gas & Electric, and Xcel Colorado; additional detail is provided in Table 4-2 below.

[10] Table 1-1 of the project SOW listed several categories of data that were not updated as part of this effort. As stated in the SOW, in cases where secondary data could not provide a better estimate than what was developed in 2013, the GDS Team did not attempt to update the data, instead defaulting to the analysis provided by EnerNOC in 2013. Examples of such data include: Housing Characteristics, Population Demographics, and Psychographics or Market Segments. The GDS Team is updating equipment saturations as part of the larger potential study; however, these updates were not developed by EMI Consulting and are not provided in this memo.

[11] 4 CSR 240-22.050(3)(A)

Table 4-2// Utility Program Benchmarks - Available Measures

Measure Name	Total	# of Utilities in Avg.	Ameren MO 3-Year Total	Peer Utility Avg.	Utilities with Program Benchmarks
AC	46,993	4	52,080	11,748	Ameren IL, Entergy Arkansas, MidAmerican (IA), Puget Sound Energy (WA)
Furnace or boiler	45,140	3		15,047	Ameren IL, MidAmerican (IA), Puget Sound Energy (WA)
Inspect HVAC ductwork	12,682	2		6,341	Arizona Public Service, Puget Sound Energy
Install 'low flow' showerheads	37,803	2	80,061	18,902	Ameren IL, Arizona Public Service
Install a dehumidifier	1,160	1	2,355	1,160	Ameren IL
Install a programmable thermostat	39,882	4	23,989	9,971	Ameren IL, Commonwealth Edison, Indianapolis Power & Light, MidAmerican (IA)
Install more energy efficient windows	2,000	1	94	2,000	Puget Sound Energy (WA)
Install one or more "Smart" power strips	3,644	2	33,258	1,822	Ameren IL, Commonwealth Edison, MidAmerican (IA)
Light bulbs	66,380	3	50,760	22,127	Ameren IL, Arizona Public Service, Commonwealth Edison
Perform regular cooling system maintenance	51,626	3	41,314	17,209	Arizona Public Service, Entergy Arkansas
Reduce water heater temperature	23,156	2	419	11,578	Ameren IL, Commonwealth Edison, MidAmerican (IA)
Refrigerator	23,610	2	4,043	11,805	Entergy Arkansas, Puget Sound Energy
Swimming pool pump	11,511	1	859	11,511	Arizona Public Service
Upgrade home insulation	31,338	4	356	7,835	Ameren IL, Arizona Public Service, Indianapolis Power & Light, Puget Sound Energy
Water heater	6,544	4	1,344	1,636	Ameren IL, Entergy Arkansas, MidAmerican (IA), Puget Sound Energy (WA)

- **Peer Utility Energy Efficiency Potential Studies:** The GDS Team reviewed potential studies published by peer utilities to obtain data on the estimated take rate (or participation rate) in these other studies for purposes of developing a comparison to the 2013 Ameren Missouri estimates. Reports from over twenty utilities and/or states were reviewed. A full list of citations is available in

Appendix A. Based on the analysis, the GDS Team was able to obtain take rates from the following utilities/jurisdictions: AR Statewide, PacifiCorp (CA, OR, WA, ID, UT, WY), NJCEP, and Ameren Illinois; of these, NJCEP and Ameren Illinois provided benchmarks for measures that were included in the Ameren Missouri 2016 Study.

4.2.3 Develop Adjustments

After obtaining a wide range of take rate data, the next step was to analyze the data to develop adjustments. Given that adjustments would be made using secondary sources, the GDS Team sought to include and consider a range of available comparison data points. The analysis considered the following:

- Ameren Missouri EE Implementation Data: using the estimated eligible customer count from the 2013 Study, the GDS Team calculated the measure penetration across the three years of implementation history.[12] Anything below 5% was considered less than expected, while 5% or above was considered on track.
- Measure Participation Benchmarks: the GDS Team compared Ameren Missouri's three-year totals (i.e. the sum of the customers who participated in the relevant measure for the years 2013, 2014, and 2015) to the average of all available benchmarks for the same measure from peer utilities to examine whether Ameren Missouri's results were higher, lower or equivalent to the average of its peers.
- Other Potential Study Benchmarks: the GDS Team compared Ameren Missouri's 2013 estimated take rates to those of the average of available other utility take rates to examine whether Ameren's estimated take rates were higher, lower or equivalent to those of its peers.
- Lift Test: As another mode of analysis, the GDS Team calculated the 1-year payback take rate by applying a multiplier to the 3-year take rate. This approach was used by AEG in the Ameren Illinois Demand Side Management Market Potential Study published in March 2016, as a means of estimating the maximum take rate. The multiplier is meant to take into consideration "lift factors" from things such as the customer financial situation or the degree to which the customer is informed about energy efficiency.[13] The team then compared the result of this calculation to the actual estimated maximum take rate from 2013 and to the average of what was seen in peer utilities. Footnote 13 provides a description of the residential and non-residential multipliers.
- Curve Fitting: For measures where there was sufficient and suitable data, we attempted to fit the results to a diffusion curve to estimate whether the three years of implementation results suggested that the take rate was reasonable and achievable over the planning horizon. In this case, we used the bass diffusion model, which relies on two coefficients (p and q or innovation and imitation) to draw an adoption curve. The model is based on a differential equation. For this analysis, the GDS Team relied upon a simulation tool developed by the Bass Basement Research Institute. Our analysis considered whether the coefficients required to match the long term curve to the three years of data fell within a realm considered reasonable by two academic reviews of p and q values from a wide range of technologies.[14]

[12] The measure penetration was calculated by summing the three years of Ameren Missouri implementation results (i.e. 2013, 2014 and 2015 implementation results) and dividing by the eligible market size. The result is the percentage of the eligible market that has participated in the measure, which is referred to as the "market penetration."

[13] On the residential side, the lift factor was a multiplier of 57% applied to the 3-year take rate; this represented a market lift resulting from the following stacked factors: Fastest Payback (0-1-year vs 3-year) 10%, Best Delivery Mechanism vs. Avg. 22%, Best Features vs. Avg. 1%, Best Customer Financial Situation vs. Avg. 14%, Most Informed vs. Avg. 11%. On the non-residential side, the lift factor was a multiplier of 54.4% applied to the 3-year take rate; this represented a market lift resulting from the following stacked factors: Fastest Payback (0-1-year vs 3-year) 8.2%, Best Delivery Mechanism vs. Avg. 13.8%, Best Features vs. Avg. 3.3%, Best Customer Financial Situation vs. Avg. 20.2%, Most Informed vs. Avg. 8.9%.

[14] For additional information on the Bass Diffusion Model, please see Bass's Basement Research Institute, available at http://www.bassbasement.org/BassModel/Default.aspx. For information on the acceptable ranges of P and Q values, please refer to the paper by Christine Holland in the bibliography of this memo.

Table 4-3 below describes each data field and the associated analysis and metric.

Table 4-3// Data Sources, Analysis Methods and Metrics

Data Field	Analysis	Metric
Ameren Missouri EE Implementation Data	Penetration	Under 5% equals low Above 5% equals on track
Measure Participation Benchmarks	Ameren Missouri 3 year totals compared to average of all available benchmarks	Higher, Lower, Equal
Other Potential Study Benchmarks	Ameren Missouri 2013 take rates compared to average of available other utility take rates	Higher, Lower, Equal
Lift Test	Compare 1-year payback take rates when calculated using lift factor applied to the 3-year payback take rate	Higher, Lower, Equal
Curve Fitting	Using three years of Ameren Missouri implementation data, fit adoption rate to a diffusion curve	Reasonable, Unreasonable P and Q values

For some measures, data was available across all the relevant analysis categories, but for others, fewer comparison points were available. Table 4-4 provides a description of the available data points as a count of measures for which the data was present.

Table 4-4// Available Data Description

Data	Residential Measures	Non-Residential Measures	Total Measures
Measures from 2013 Study Appendix Tables A1 and D1 selected for Updating	27	37	64
Measures with Ameren Missouri Implementation Results	14	27	41
Measures with Peer Program Measure Benchmarks	17	0	17
Measures with Peer Potential Study Take Rate Benchmarks	24	28	52
Measures with Suitable Data for Curve Fitting	7	4	11
Measures for which Lift Test Could be Calculated	22	34	56
Measure for Which Take Rate Has Changed Since 2013	19	33	52

4.3 FINDINGS

The GDS Team reviewed a total of 64 measures; of those, 52 (33 non-residential and 19 residential) were recommended for change. Changes varied by measures with some take rates increasing and others decreasing. The basis for each measure adjustment is provided in Appendix A. The following section provides first a set of tables depicting the take rates by sector, measure and payback scenario, followed by the take rates by market segment and finally a comparison of the take rates in 2016 versus the 2013 estimated take rates for the same measures.

Table 4-5 below depicts the 2016 residential take rates, followed by Table 4-6 depicting the non-residential take rates. The values were adjusted according to the payback scenarios modeled in the 2013 Study.

Table 4-5// 2016 Residential Take Rates

Residential Measure	2016 Ameren MO 1-year Payback	2016 Ameren MO 3-year Payback	2016 Ameren MO 5-year Payback
Category 1 - Programs / measures for purchasing / installing energy efficiency equipment			
Refrigerator	61%	39%	34%
AC	53%	36%	31%
Furnace or boiler	53%	36%	31%
Water heater	55%	38%	32%
TV	51%	38%	34%
PC	50%	30%	26%
Stovetop or range	52%	36%	32%
Clothes dryer	57%	36%	31%
Swimming pool pump	46%	29%	25%
Light bulbs	62%	42%	35%
Category 2 - Programs / measures for improving energy efficiency of existing systems			
Install more energy efficient windows	47%	30%	24%
Install a whole house / attic fan	26%	22%	18%
Inspect HVAC ductwork	35%	30%	24%
Upgrade HVAC ductwork insulation (Hot Water Heater Pipe Wrap)	48%	36%	31%
Upgrade home insulation	49%	36%	31%
Install exterior lighting controls	47%	35%	29%
Install an Air Purifier (Dehumidifier)	41%	26%	21%
Perform regular cooling system maintenance	52%	37%	30%
Perform regular heating system maintenance	52%	37%	31%
Install a programmable thermostat	52%	33%	27%
Install 'low flow' showerheads	39%	25%	20%
Install one or more "Smart" power strips	51%	37%	31%
Category 3 - Programs / measures not requiring an investment by the customer			
Reduce water heater temperature		30%	
Turn down the heating / cooling while sleeping or away		43%	
Category 4 - Programs / measures for which Ameren MO incentive would completely eliminate the price difference			

Residential Measure	2016 Ameren MO 1-year Payback	2016 Ameren MO 3-year Payback	2016 Ameren MO 5-year Payback
Refrigerator		39%	
Television		37%	
Dehumidifier		33%	

Table 4-6// Non-Residential Take Rates

Measure	2016 Ameren MO 1-year Payback	2016 Ameren MO 3-year Payback	2016 Ameren MO 5-year Payback
Category 1 - Programs / measures for purchasing / installing energy efficiency equipment			
AC / Chiller Unit	56%	25%	17%
Cooling System	55%	27%	19%
Light Bulbs	70%	46%	33%
Heating System	55%	26%	18%
Copier / Printer	47%	39%	29%
PC	59%	38%	28%
Refrigeration Unit	55%	27%	20%
Server	51%	26%	17%
Cooking Equipment	58%	28%	22%
Category 2 - Programs / measures for improving energy efficiency of existing systems			
Maintain cooling system regularly	55%	26%	14%
Maintain heating system regularly	71%	46%	34%
Install a timer on pool pump	73%	47%	38%
Install a programmable thermostat	71%	46%	37%
Upgrade portions of your lighting system	68%	44%	33%
Install exterior lighting controls	58%	32%	23%
Purchase EE pumps or motors for HVAC system	68%	44%	36%
Install EE fans on chiller units	59%	31%	24%
Install variable speed drives on HVAC system	63%	34%	27%
Add ventilation system volume controls	62%	32%	24%
Install variable speed drives on chiller pumps	63%	34%	27%
Install an Economizer	63%	31%	24%
Implement "re-commissioning" of HVAC system	56%	36%	27%
Install an Energy Management System	59%	38%	30%
Install occupancy / motion sensors for lighting	57%	29%	21%

Measure	2016 Ameren MO 1-year Payback	2016 Ameren MO 3-year Payback	2016 Ameren MO 5-year Payback
Install "low flow" nozzles or faucet aerators	52%	25%	16%
Install interior lighting sensors / timers	54%	28%	21%
Install reflective film on exterior windows	49%	32%	24%
Install a variable speed compressor on refrigeration unit(s)	52%	34%	29%
Install a dishwasher pre-rinse spray valve	48%	31%	23%
Category 3 - Programs / measures for which Ameren MO incentive would completely eliminate the price difference			
Purchase EE motors or pumps for non-HVAC equipment	62%	33%	26%
Install Variable Speed Drives on one or more non-HVAC pumps/ motors	57%	31%	25%
Install/ upgrade an advanced optimization control system on industrial compressed air system	54%	35%	28%
Efficient rewind of motors	49%	32%	25%
Install a timer or altering the control algorithm on industrial processes	46%	30%	24%
Category 4 - Programs / measures not requiring an investment by the customer			
Reduce thermostat setting during the winter		36%	
Raise your thermostat setting during the summer		35%	
Reduce water heater temperature		36%	

4.3.1 Take Rates by Market Segment

Table 4-7 and Table 4-8 on the following pages provide the take rates by market segment. These segments are identical to those that were developed in the 2013 Study as this is not a data area that can be updated using secondary sources; however, the take rates have changed based on the adjustments made to the general population take rates. Utility market segmentation studies are custom studies that are generally based on survey or market research with the utility customers; secondary sources cannot be leveraged to understand the attitudes, behaviors and segments within a particular utility service area as this research is not transferrable from one jurisdiction to the next. That said, given that the take rates were updated, the GDS Team was able to adjust the market segment take rates in proportion to the overall measure adjustment. The following tables provide the 2013 Market Segments with updated 2016 take rates.

Table 4-7// Residential Take Rates by Market Segment

Measure Name	Practical Idealists	Active Conservers	Cost-Focused Conservers	Affluent & Feature-Focused	Unmotivated & Uninformed	Low Interest, Little Action
Measures for purchasing/installing energy efficient equipment						
Light bulbs	57%	53%	39%	38%	38%	31%
Refrigerator	49%	45%	38%	40%	37%	30%
Water heater	49%	45%	36%	37%	31%	27%

Measure Name	Practical Idealists	Active Conservers	Cost-Focused Conservers	Affluent & Feature-Focused	Unmotivated & Uninformed	Low Interest, Little Action
Furnace / boiler	48%	43%	33%	37%	29%	26%
Clothes dryer	48%	43%	34%	36%	33%	26%
AC	48%	45%	32%	37%	30%	26%
Stove / range	49%	44%	34%	37%	31%	26%
TV	51%	46%	33%	39%	33%	28%
PC	43%	38%	27%	30%	27%	20%
Pool pump	38%	32%	19%	35%	22%	21%
Measures for improving energy efficiency of existing systems						
Maintain cooling system regularly	50%	44%	32%	37%	33%	26%
Maintain heating system regularly	51%	43%	34%	36%	34%	27%
Install a programmable thermostat	49%	38%	29%	29%	27%	24%
Install 'Smart' power strips	53%	44%	35%	32%	33%	28%
Install exterior lighting controls	49%	40%	28%	33%	31%	26%
Install more EE exterior windows	43%	35%	26%	29%	22%	23%
Inspect, repair, and seal duct-work	44%	36%	23%	28%	27%	21%
Add / upgrade insulation	51%	39%	34%	33%	30%	28%
Add duct-work insulation	50%	42%	32%	34%	32%	27%
Install a de-humidifier	39%	34%	21%	23%	21%	19%
Install low-flow shower-heads	39%	32%	23%	18%	20%	18%
Install a whole house / attic fan	32%	27%	19%	20%	21%	16%
Measures not requiring an adjustment by the customer						
Turning down the heating/cooling systems while sleeping/away	49%	49%	45%	42%	43%	37%
Reduce water heater temperature	38%	37%	35%	26%	28%	22%
Get rid of secondary refrigerator	33%	29%	23%	20%	27%	20%
Measures for Which Ameren MO Incentive Would Completely Eliminate the Price Difference						
Purchase a higher than standard efficiency refrigerator	51%	48%	37%	39%	37%	30%
Purchase a higher than	49%	47%	34%	37%	34%	27%

Measure Name	Practical Idealists	Active Conservers	Cost-Focused Conservers	Affluent & Feature-Focused	Unmotivated & Uninformed	Low Interest, Little Action
standard efficiency television						
Purchase a higher than standard efficiency dehumidifier	44%	44%	32%	32%	28%	24%

Table 4-8// Non-Residential Take Rates by Market Segment

Measure Name	Cost-Focused Conservers	Active Conservers	Practical Idealists	Unmotivated & Uninformed	Cost-Focused Skeptics	Low Interest, Little Action
Category 1: Programs / Measures for Purchasing / Installing Energy Efficient Equipment						
AC / Chiller Unit	36%	34%	25%	26%	18%	10%
Copier / Printer	48%	46%	45%	40%	28%	33%
Cooling System	35%	37%	29%	26%	19%	21%
Light Bulbs	65%	58%	56%	40%	32%	34%
Heating System	39%	37%	24%	28%	20%	10%
Server	40%	35%	29%	30%	16%	19%
PC	47%	44%	40%	39%	29%	36%
Refrigeration Unit	44%	40%	21%	27%	18%	18%
Cooking Equipment	44%	41%	26%	27%	17%	14%
Category 2: Programs / Measures for Improving Energy Efficiency of Existing Systems						
Maintain cooling system regularly	37%	33%	36%	25%	16%	15%
Maintain heating system regularly	57%	52%	55%	45%	36%	38%
Install a timer on pool pump	66%	47%	59%	N/A	32%	N/A
Install a programmable thermostat	56%	52%	50%	48%	36%	39%
Upgrade portions of your lighting system	58%	55%	49%	42%	33%	32%
Install exterior lighting controls	45%	43%	38%	32%	22%	16%
Purchase EE pumps or motors for HVAC system	55%	56%	42%	44%	34%	29%
Install EE fans on chiller units	21%	52%	51%	N/A	34%	N/A
Install variable speed drives on HVAC system	44%	48%	34%	35%	25%	22%

Measure Name	Cost-Focused Conservers	Active Conservers	Practical Idealists	Unmotivated & Uninformed	Cost-Focused Skeptics	Low Interest, Little Action
Add ventilation system volume controls	44%	45%	37%	34%	21%	17%
Install variable speed drives on chiller pumps	27%	58%	36%	N/A	45%	N/A
Install an Economizer	20%	54%	33%	N/A	42%	N/A
Implement “re-commissioning” of HVAC system	50%	45%	39%	36%	27%	25%
Install an Energy Management System	54%	50%	41%	34%	28%	27%
Install occupancy / motion sensors for lighting	41%	41%	34%	26%	19%	18%
Install “low flow” nozzles or faucet aerators	37%	34%	23%	27%	16%	15%
Install interior lighting sensors / timers	41%	39%	34%	26%	19%	16%
Install reflective film on exterior windows	49%	37%	35%	32%	22%	21%
Install a variable speed compressor on refrigeration unit(s)	44%	52%	32%	30%	27%	23%
Install a dishwasher pre-rinse spray valve	53%	42%	27%	29%	23%	22%
Category 3: Programs / Measures for Which Ameren MO Incentive Would Completely Eliminate the Price Difference						
Purchase EE motors or pumps for non-HVAC equipment	50%	47%	29%	24%	25%	8%
Install Variable Speed Drives on one or more non-HVAC pumps/ motors	46%	45%	29%	21%	22%	7%
Install/ upgrade an advanced optimization control system on industrial compressed air system	53%	46%	32%	35%	25%	21%
Efficient rewind of motors	45%	44%	26%	27%	26%	17%
Install a timer or altering the control algorithm on industrial processes	44%	43%	26%	25%	26%	9%
Category 4: Programs / Measures Not Requiring an Investment by the Customer						
Reduce thermostat setting during the winter	40%	42%	41%	37%	32%	30%
Raise your thermostat setting during the summer	39%	39%	37%	34%	32%	29%
Reduce water heater temperature	44%	39%	36%	34%	32%	34%

4.3.2 Comparative Assessment of the Market Research Data

Table 4-9 and Table 4-10 describe the 2013 take rate by measure and payback scenario alongside the 2016 take rates. These are provided as a means to easily compare the previous take rate to the updated 2016 take rate.

Table 4-9// Residential Take Rates 2013 vs 2016

Measure	2013 1-year Payback	2013 3-year Payback	2013 5-year Payback	2016 1-year Payback	2016 3-year Payback	2016 5-year Payback
Category 1 - Programs / measures for purchasing / installing energy efficiency equipment						
Refrigerator	43%	39%	34%	61%	39%	34%
AC	40%	36%	31%	53%	36%	31%
Furnace or boiler	40%	36%	31%	53%	36%	31%
Water heater	42%	38%	32%	55%	38%	32%
TV	35%	32%	28%	51%	38%	34%
PC	33%	30%	26%	50%	30%	26%
Stovetop or range	37%	33%	29%	52%	36%	32%
Clothes dryer	40%	36%	31%	57%	36%	31%
Swimming pool pump	32%	29%	25%	46%	29%	25%
Light bulbs	44%	39%	32%	62%	42%	35%
Category 2 - Programs / measures for improving energy efficiency of existing systems						
Install more energy efficient windows	35%	30%	24%	47%	30%	24%
Install a whole house / attic fan	26%	22%	18%	26%	22%	18%
Inspect HVAC ductwork	35%	30%	24%	35%	30%	24%
Upgrade HVAC ductwork insulation	34%	29%	24%	48%	36%	31%
Upgrade home insulation	34%	29%	24%	49%	36%	31%
Install exterior lighting controls	35%	30%	24%	47%	35%	29%
Install an Air Purifier	32%	26%	21%	41%	26%	21%
Perform regular cooling system maintenance	40%	34%	27%	52%	37%	30%
Perform regular heating system maintenance	40%	33%	27%	52%	37%	31%
Install a programmable thermostat	39%	33%	27%	52%	33%	27%
Install 'low flow' showerheads	30%	25%	20%	39%	25%	20%
Install one or more "Smart" power strips	37%	31%	25%	51%	37%	31%
Category 3 - Programs / measures not requiring an investment by the customer						
Reduce water heater temperature		30%			30%	

Measure	2013 1-year Payback	2013 3-year Payback	2013 5-year Payback	2016 1-year Payback	2016 3-year Payback	2016 5-year Payback
Turn down the heating / cooling while sleeping or away		43%			43%	
Category 4 - Programs / measures for which Ameren MO incentive would completely eliminate the price difference						
Refrigerator		39%			39%	
Television		37%			37%	
Dehumidifier		33%			33%	

Table 4-10// Non-Residential Take Rates 2013 vs 2016

Measure	2013 1-year Payback	2013 3-year Payback	2013 5-year Payback	2016 1-year Payback	2016 3-year Payback	2016 5-year Payback
Category 1 - Programs / measures for purchasing / installing energy efficiency equipment						
AC / Chiller Unit	56%	49%	41%	56%	25%	17%
Cooling System	55%	49%	41%	55%	27%	19%
Light Bulbs	55%	46%	33%	70%	46%	33%
Heating System	55%	48%	40%	55%	26%	18%
Copier / Printer	47%	39%	29%	47%	39%	29%
PC	45%	38%	28%	59%	38%	28%
Refrigeration Unit	45%	40%	33%	55%	27%	20%
Server	45%	37%	28%	51%	26%	17%
Cooking Equipment	43%	38%	32%	58%	28%	22%
Category 2 - Programs / measures for improving energy efficiency of existing systems						
Maintain cooling system regularly	55%	46%	34%	55%	26%	14%
Maintain heating system regularly	55%	46%	34%	71%	46%	34%
Install a timer on pool pump	54%	47%	38%	73%	47%	38%
Install a programmable thermostat	53%	46%	37%	71%	46%	37%
Upgrade portions of your lighting system	53%	44%	33%	68%	44%	33%
Install exterior lighting controls	50%	44%	35%	58%	32%	23%
Purchase EE pumps or motors for HVAC system	49%	44%	36%	68%	44%	36%
Install EE fans on chiller units	48%	43%	36%	59%	31%	24%

Measure	2013 1-year Payback	2013 3-year Payback	2013 5-year Payback	2016 1-year Payback	2016 3-year Payback	2016 5-year Payback
Install variable speed drives on HVAC system	47%	41%	34%	63%	34%	27%
Add ventilation system volume controls	46%	40%	32%	62%	32%	24%
Install variable speed drives on chiller pumps	46%	41%	34%	63%	34%	27%
Install an Economizer	46%	41%	34%	63%	31%	24%
Implement “re-commissioning” of HVAC system	44%	36%	27%	56%	36%	27%
Install an Energy Management System	43%	38%	30%	59%	38%	30%
Install occupancy / motion sensors for lighting	42%	37%	29%	57%	29%	21%
Install “low flow” nozzles or faucet aerators	41%	34%	25%	52%	25%	16%
Install interior lighting sensors / timers	41%	35%	28%	54%	28%	21%
Install reflective film on exterior windows	39%	32%	24%	49%	32%	24%
Install a variable speed compressor on refrigeration unit(s)	39%	34%	29%	52%	34%	29%
Install a dishwasher pre-rinse spray valve	37%	31%	23%	48%	31%	23%
Category 3 - Programs / measures for which Ameren MO incentive would completely eliminate the price difference						
Purchase EE motors or pumps for non-HVAC equipment	45%	40%	33%	62%	33%	26%
Install Variable Speed Drives on one or more non-HVAC pumps/ motors	41%	37%	31%	57%	31%	25%
Install/ upgrade an advanced optimization control system on industrial compressed air system	40%	35%	28%	54%	35%	28%
Efficient rewind of motors	37%	32%	25%	49%	32%	25%
Install a timer or altering the control algorithm on industrial processes	34%	30%	24%	46%	30%	24%
Category 4 - Programs / measures not requiring an investment by the customer						
Reduce thermostat setting during the winter		36%			36%	
Raise your thermostat setting during the summer		35%			35%	
Reduce water heater temperature		36%			36%	

4.3.3 Characterization of the Low Income Market

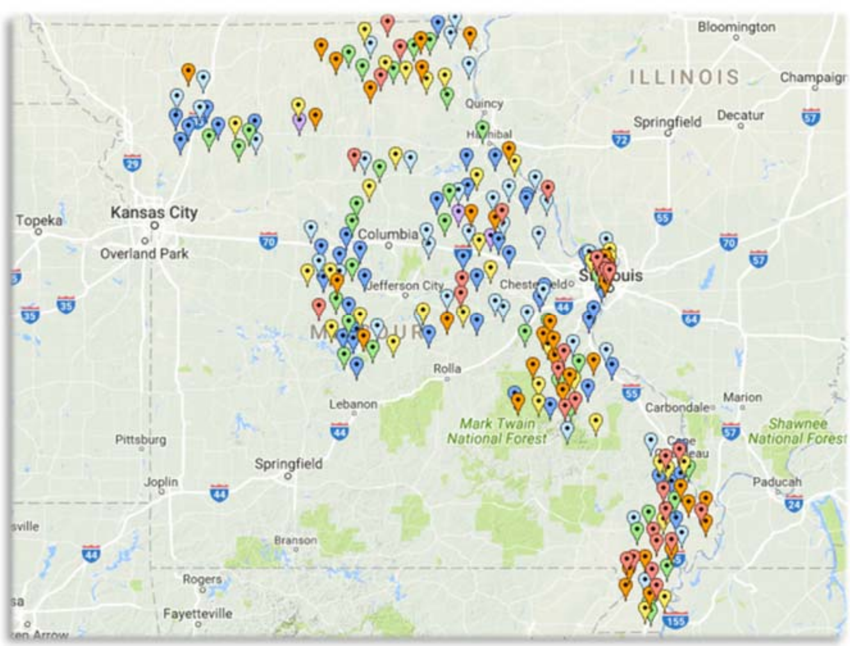
Ameren Missouri expressed a particular interest in understanding characteristics of its low income customer population. Given that no primary research would be conducted with customers, the GDS Team obtained a list of zip codes serviced by Ameren Missouri and used this list to extract relevant data on populations in those zip codes from the US Census 2014 American Community Survey. Through this process, the GDS Team was able to estimate the total number of Ameren Missouri customers who fall within 200% of the federal poverty level and to extract information on the locations of these customers and the housing stock characteristics in the zip codes in which they live. The GDS Team selected the 200% of the federal poverty level criteria as this is the criteria for participation in the Community Savers program. In real numbers, this translates into a household income of $48,500 for a family of four, and scales downward for smaller families and upward for larger families. The 2016 thresholds are provided in Table 4-11 below.

Table 4-11 // 200% of the 2016 Federal Poverty Level Qualifying Incomes

Household Size	Income
1	$23,540
2	$31,860
3	$40,180
4	$48,500
5	$56,820
6	$65,140
7	$73,460
8	$81,780

For this analysis, the data extracted from the census corresponds to household incomes of less than $48,500 regardless of household size; this means that the total number of households included in the analysis might be over-counting customers with fewer individuals living in the home, or households with larger incomes who would have qualified at a higher income threshold. In addition to the census data, the GDS Team also reviewed secondary literature to gather some additional information on the economic conditions and trends within the state. The following section describes the findings from this analysis.

Figure 4-2 // Locations of Low Income Population



4.3.3.1 Low Income Market Size and Characteristics

As described above, the GDS Team analyzed the low income market in Ameren Missouri's service area through a process of matching zip codes serviced by Ameren Missouri to data collected by the US Census on the populations that dwell within those zip codes. Based on this analysis, the team concluded that greater than 54%, or roughly 569,000 households, fall within 200% of the federal poverty level.[15] Through an analysis of the Ameren Missouri energy efficiency program implementation data, the GDS Team concluded that the 2013-2015 estimated market penetration – that is the percentage of the customers that have implemented energy efficiency measures through the Community Savers program is 4.02%. The estimate sums the count of customers who participated in the Community Savers program and divides that by the estimated low income household count. In terms of the housing characteristics within these zip codes, an estimate 62% of the dwellings are owner-occupied while 38% are occupied by renters. 65% of the units are single family detached homes, 6% are mobile home and the remaining 29% have two or more units within them. Finally, an estimate 45% of these dwellings were constructed before 1960. All of these estimates were calculated using a weighted average, weighted by the total number of households in each zip code.

Figure 4-2 displays the locations of zip codes in which a large percentage of the population falls within 200% of the federal poverty level. Red and orange dots identify zip codes in which more than 69% of households meet this criteria, while yellow, blue, and purple dots correspond to zip codes in which 51% to 68% of the households meet these criteria.

4.3.3.2 General Economic Trends and Information

The GDS Team also reviewed sources on general economic info for the state of Missouri. According to the Missouri Economic Research and Information Center, the cost of living in Missouri in 2016 is 89.9% of the national average, a slight improvement from 91.6 percent in the previous year's analysis. This ranks Missouri as the 8th lowest cost of living in the United States with a lower than national average cost in all categories with the exception of utilities where the cost was slightly higher than the national average. Table 4-12 below displays Missouri's cost index in all categories as well as the indices for the lowest and highest cost states and the national average.

Table 4-12// Missouri Cost Of Living Compared to the Lowest and Highest Ranking States

State	Rank	Index	Grocery	Housing	Utilities	Transportation	Health	Misc.
Mississippi	1	84.4	94.3	64.8	88.4	93.8	89	92
Missouri	8	89.9	96.5	73.8	101.9	93.1	97.2	95.1
Hawaii	51	167.3	154.3	230.5	208.4	130.3	113.1	125.6
National Average		100	100	100	100	100	100	100

4.4 TAKE RATE SUMMARY

The data included in this section of the report were developed as part of the overall market potential study led by GDS Associates. The content was used to help inform the estimates of energy efficiency program potential. The analysis was completed using secondary materials, as well as Ameren Missouri's implementation results. Given the relative uncertainty associated with this type of research, an effort was made to gather a wide range of comparable data from peer utilities to help benchmark and bolster the accuracy of the results. This section documents the approach, methods and findings from the

[15] It is important to note that this analysis assumes 100% of the zip code is serviced by Ameren Missouri; in some cases, this assumption may be inaccurate, and could, therefore, overestimate the number of households that fall within this threshold and are serviced by Ameren Missouri. Similarly, the estimate of low income households may be over or under-counting households as a results of the qualifying income thresholds discussed in the main body of this memo.

secondary analysis. A presentation of these take rate forecasts was also delivered to Ameren Missouri staff and stakeholders on September 9, 2016 via webinar.

5 BASELINE FORECAST

5.1 INTRODUCTION

The load forecast is a critical input into Ameren Missouri's ("Ameren") 2016 Demand Side Management ("DSM") Potential Study, having various uses in estimation of Residential, Commercial, and Industrial potential. Therefore, GDS Associates, Inc. ("GDS") took considerable time and effort to review Ameren's most recently completed load forecast models and documentation to produce the various forecast components necessary as inputs into the Potential Study. The report describes the various ways in which the forecast is used for other aspects of the study, presents the baseline and disaggregated forecasts, and describes the methodology and data sources used by GDS for the purposes of generating the load forecasts that were used in the potential analysis.

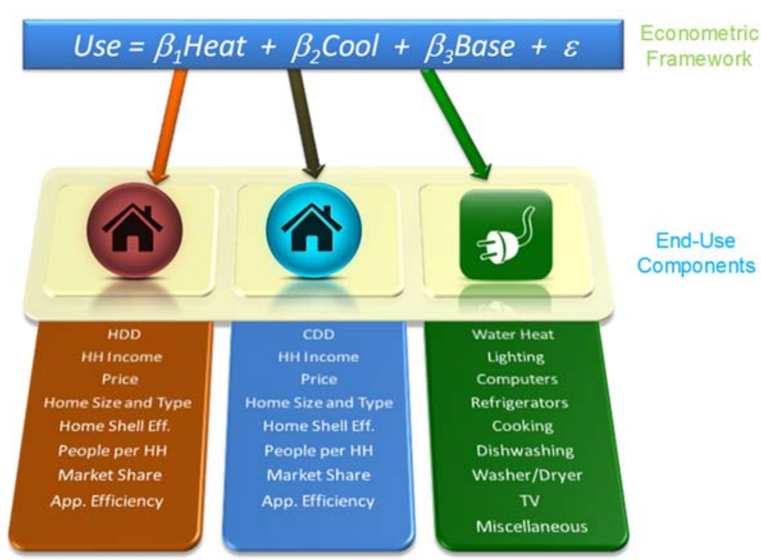
5.2 AMEREN MISSOURI'S LOAD FORECASTING SYSTEM

Ameren employs a sophisticated load forecasting system that uses econometric and Statistically Adjusted End-Use ("SAE") models to project number of consumers, average consumption per consumer, and total energy sales by class. Residential, Commercial, and Industrial consumers are projected using traditional econometric techniques. Residential average usage and commercial energy sales are projected using SAE model specifications. Industrial energy sales are projected using econometric techniques.

SAE models are a hybrid forecasting tool, blending the strengths of end-use engineering models with econometric techniques. SAE models are employed by many utilities, included Investor Owned Utilities, cooperatives, and municipals. The models have withstood regulatory scrutiny for over a decade.

A residential SAE model specification takes end-use data drawn from utility, regional, and even national sources and develops monthly end-use indices designed to predict average household consumption. The indices are then adjusted through a least squares regression to statistically fit historical usage patterns. The end-use data includes market share of key electric consuming appliances, average device efficiency trends, average building shell efficiency trends, price elasticity of demand, income elasticity of demand, and elasticity associated with the average number of people per household. A cooling index is developed to represent space cooling load and is further modified by Cooling Degree Days to incorporate summer weather into the model. Likewise, a heating index representing space heating is modified by Heating Degree Days. Finally, a base index is developed to represent consumption of all other end-uses in the home.

Figure 5-1 // SAE Model Framework



A commercial sector SAE model's specification is very similar to a residential specification, with end-use energy intensity indices developed based on area employment in various industry codes. National and regional commercial data is used to estimate end-use consumption for various industries (for example, restaurants will have higher cooking usage shares than offices).

Ameren uses system-specific data for appliance market shares. Average device and home shell efficiencies are developed by Itron and represent regional adjustments to Annual Energy Outlook ("AEO") projections prepared by the Energy Information Administration ("EIA"). Other data sources for the SAE framework include national surveys conducted by the EIA and the US Census Bureau, such as the Residential Energy Consumption Survey ("RECS") and the Commercial Building Energy Consumption Survey ("CBECS").

Ameren also projects impacts of DSM programs it has run in the past. Three different programs are projected:

- Programs initiated prior to the Missouri Energy Efficiency Investment Act ("MEEIA")
- MEEIA Cycle 1 programs
- MEEIA Cycle 2 programs

The detailed forecasting framework developed and used by Ameren provides a rich data source for GDS for developing the various baseline forecasts and to disaggregate energy sales projections as needed for the Potential Study. The next section will describe how the forecasts are used in the Potential Study.

5.3 USE OF LOAD FORECAST IN POTENTIAL STUDY

5.3.1 Residential Sector

For the Residential Potential analysis, GDS employs a bottom-up approach to estimate total class potential. Models are built at the measure and end-use level and are then aggregated into program and class potentials. To accomplish this, GDS' models require detailed information about appliance market shares, efficiencies, consumption patterns, and useful lives. Ameren's detailed load forecast databases provide many of these key inputs into the bottom-up modeling approach. Furthermore, the model differentiates between housing type and age of home (new versus existing construction). The load forecast provides value to the Residential Potential analysis in the following ways:

- Ameren's SAE databases provide appliance stock information and projections.
- Ameren's SAE databases provide assumptions regarding average device efficiencies on the system.
- The load forecast represents the baseline upon which potential as a percentage is computed. Total potential energy and demand savings are estimated using the GDS models, then potential is expressed as a percentage of the load forecasted baseline energy sales. The baselines are described in more detail below.
- End-use energy sales projections from the load forecast are then used to check the GDS Potential model. GDS will aggregate measure-level data in the energy efficiency potential models and verify the aggregated totals relative to the forecasted end-use sales.

5.3.2 Commercial and Industrial Sector

For Commercial and Industrial ("C&I") Potential, GDS employs a top-down approach to estimate total class potential. The load forecast of total class energy sales is the starting point for this modeling approach. The forecast is broken down to total energy sales by market segment by end-use. Then, DSM potential is estimated as a proportion of the end-use sales. Obviously, this approach relies directly on the load forecast. For many utilities that GDS has worked with, end-use forecast sales are not available. However, for the commercial classification, Ameren's SAE modeling framework allows GDS to start with a forecast that is disaggregated by end-use. The load forecast also provides the baseline upon which potential is measured on a percentage basis.

5.4 BASELINE LOAD FORECAST

Two different baseline load forecasts will be used to express potential in the Study: the Naturally Occurring Forecast and the Business As Usual ("BAU") Forecast.

5.4.1 Naturally Occurring Forecast

The Naturally Occurring Forecast represents energy and demand sales projections with current energy efficiency codes and standards (projected or possible changes in codes and standards are not contemplated), with naturally occurring efficiency impacts included, and with savings from current DSM[16] programs included. Naturally occurring efficiency represents reductions in energy sales due to the fact that some proportion of consumers and businesses purchase and install equipment that is more efficient than minimums defined in current codes and standards and independent of formal DSM programs.

The Naturally Occurring Forecast will be the forecast used for the C&I top-down estimations of program potential, because this is the forecast that best represents expected energy sales to the C&I class.

Potential savings measured against the Naturally Occurring Forecast represent ***net savings***. The net savings represents the percentage savings potential of a program versus what energy sales would be expected to be given the current codes and standards, the current DSM programs already in place, and naturally occurring efficiency effects.

Figure 5-2// Net Savings Formula

5.4.2 Business As Usual Forecast

The BAU Forecast is similar to the Naturally Occurring forecast but with one difference. Like the Naturally Occurring forecast, the BAU forecast includes current codes and standards and includes current DSM program impacts. However, the BAU forecast excludes impacts associated with naturally occurring efficiency.

Potential savings measured against the BAU Forecast represent ***gross savings***. Because the BAU baseline is higher than the Naturally Occurring baseline, gross savings will be a lower reported potential percentage. The gross savings represent the percentage of savings potential against the current codes and standards.

Figure 5-3// Gross Savings Formula

[16] For ease of discussion, current DSM will be used throughout to include pre-MEEIA programs and MEEIA Cycle 1 and MEEIA Cycle 2 programs.

5.4.3 Baseline Forecasts

The figures below show the Naturally Occurring and BAU Forecasts for the Residential, Commercial, and Industrial classifications. On each chart, the shaded area between the two forecasts represents the estimated amount of naturally occurring efficiency savings. The method by which GDS developed each baseline and the amount of naturally occurring efficiency is discussed in detail in Section 5.4.4 below. It is important to note that GDS' models will estimate potential savings in terms of energy and demand savings and then express those potentials on net and gross savings bases. Therefore, the MWh savings potentials will be the same for both gross and net savings.

Figure 5-4// Residential Baseline Forecasts

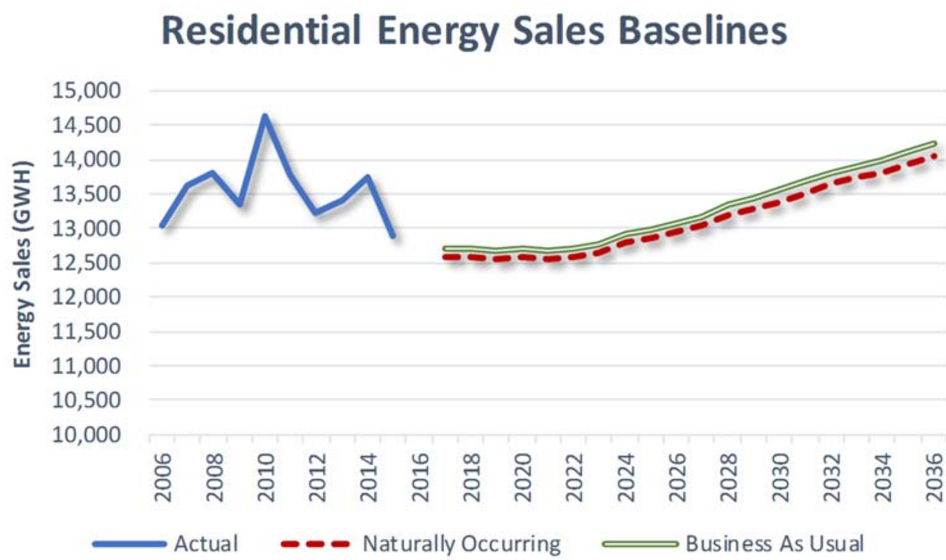


Figure 5-5// Commercial Baseline Forecasts

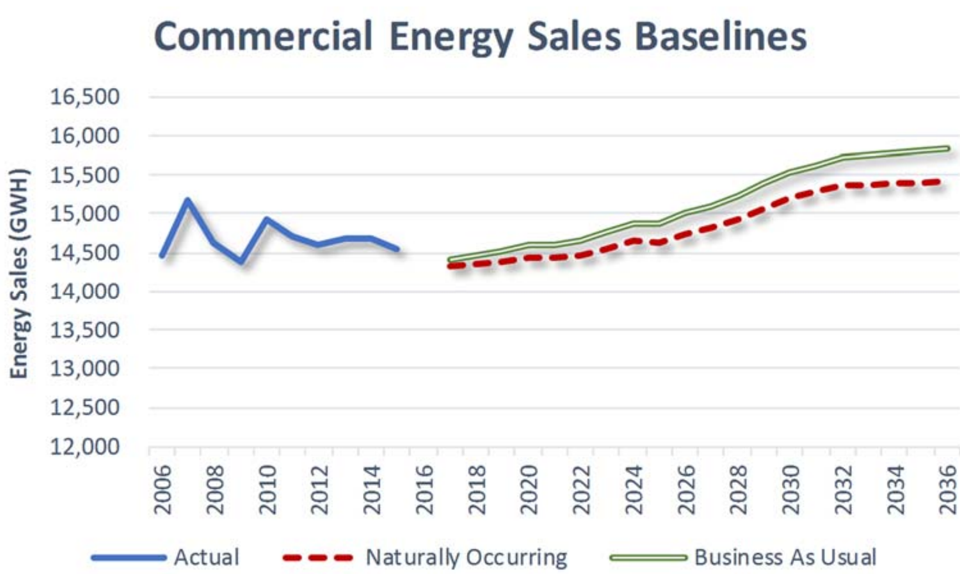
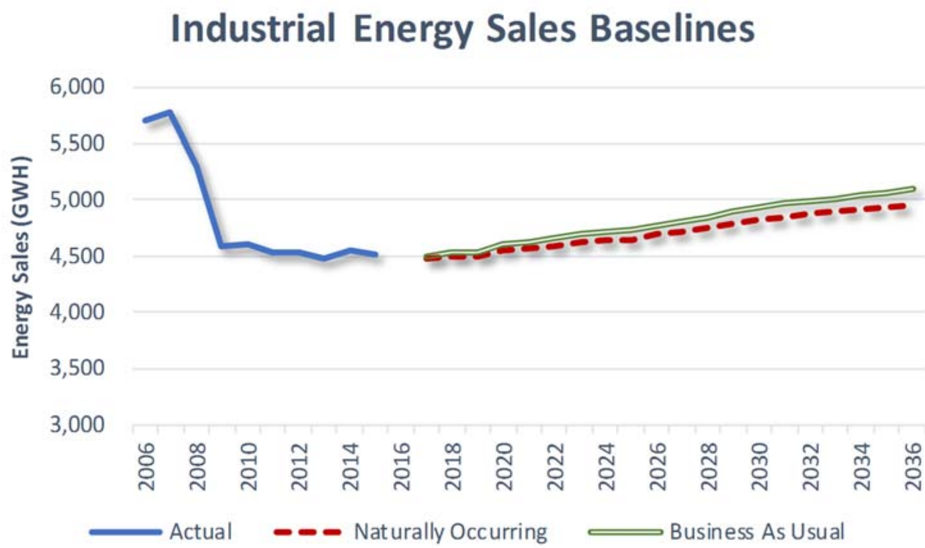


Figure 5-6// Industrial Baseline Forecasts



5.4.4 Baseline Development Methodology

GDS worked with Ameren's forecasting staff and forecasting models and databases to prepare the Naturally Occurring baseline and the BAU baseline Forecasts.

5.4.4.1 Naturally Occurring Baseline Methodology

As described above, the Naturally Occurring Forecast includes current codes and standards, includes naturally occurring efficiency savings, and includes current DSM impacts. In order to develop the Naturally Occurring Forecast, GDS started with Ameren's currently completed load forecast.

Current Codes and Standards

Ameren's SAE forecasting framework includes projections of average end-use appliance efficiencies. The efficiency projections are sourced from the EIA's Annual Energy Outlook (AEO), with adjustments made by Itron to reflect regional (Midwest) appliance stock distribution. These projections include all current codes and standards with respect to energy efficient appliances and thermal shell efficiency for construction. Furthermore, the EIA series does not project changes in the codes and standards. Appendix B of this report provides the listing of codes and standards captured by the Ameren efficiency assumptions. Given use of this series, the Ameren forecast includes current codes and standards consistent with the Naturally Occurring Forecast.

Naturally Occurring Efficiency Savings

The end-use appliance efficiency trends in the SAE model framework show appliance efficiency changing over time. As stated above, the projected efficiency improvements are not a function of projected changes in codes and standards. Therefore, appliance efficiency gains projected into the future are a function of some consumers replacing below-standard equipment at the standard and other consumers purchasing equipment more efficient than the standard without the impetus of a DSM program. The rising trend in efficiency, then, is representative of naturally occurring efficiency. Figure 5-7 below shows an example for Central Air Conditioning, in which the average efficiency over time reaches a SEER rating of just under 15, while the minimum standard currently in effect is 13. Without a projected change in the standard, the average SEER exceeding the standard threshold is attributable to naturally occurring efficiency. Therefore, the Ameren SAE models include naturally occurring efficiency savings consistent with the Naturally Occurring Forecast.

Figure 5-7 // Average SEER of Central Air Conditioners with Naturally Occurring Efficiency Effects

Current DSM Impacts

Ameren provided GDS with a projection of energy savings for all current DSM programs. Although each Cycle only lasts three years, the effects of those measures enacted during the Cycle last beyond that three-year period. An important question is how to handle the savings of those programs at the expiration of the current measure. GDS evaluated three possible options:

1) Assume the full savings potential is repeated. This implicitly assumes all participants in the program would participate again at the same level, even without the program in place, or a 100% transformation of the participant population. This indicates full transformation of the entire DSM market from Cycles 1 and 2.
2) In the second approach, it is assumed that free riders only would continue to install efficient equipment or behave efficiently even without the DSM program in place but all others would revert back to the minimum standard of efficiency. This represents an approach in which none of the participants that were not already actively engaged in efficiency and conservation would have been transformed by participation in the program. For each end-use, GDS used the 2015 Efficiency Measurement & Verification ("EM&V") reports for current DSM programs to estimate free ridership for each end-use. For instance, the average free ridership for residential lighting programs was 19.7%. Therefore, GDS would assume 19.7% of lighting efficiency savings would repeat after the end of the life of the lighting programs and 80.3% would revert to the current minimum codes and standards for lighting (governed by the Energy Independence and Security Act ("EISA") of 2007).
3) The last approach is one in which free riders remain engaged in efficient behaviors plus some portion of the remaining participant population is transformed. In 2014, Ameren conducted market research of the residential and commercial sectors. Customers were segmented according to perceptions to energy efficiency and conservation. GDS has assumed that Active Conservers and Cost-Focused Conservers would be the proportion of the population transformed. For the residential sector, 13% of consumers were Active Conservers and 9% were Cost-Focused Conservers, totaling to a 22% assumed transformation rate in excess of free ridership. For the C&I sector, 25% of the market is assumed transformed, based on 12% of the sector being Active Conservers and 13% being Cost-Focused Conservers.

The selection between the three options has an impact on the marketplace that remains as potential targets for new DSM programs and therefore is an important assumption for the Potential Study. The GDS and Ameren team has selected the third option, in which a portion of the program participants in excess of free riders are transformed and continue to exhibit efficient behaviors at the expiration of current DSM measures. This approach recognizes the likelihood that some portion of program participants that were not originally free riders would likely continue to exhibit efficient behaviors but that not all such consumers would do so.

5.4.4.2 Business As Usual Baseline Methodology

The BAU Forecast is the same as the Naturally Occurring Forecast except that naturally occurring efficiency effects are added back to represent what sales would be if all consumers installed equipment only at the currently enacted codes and standards.

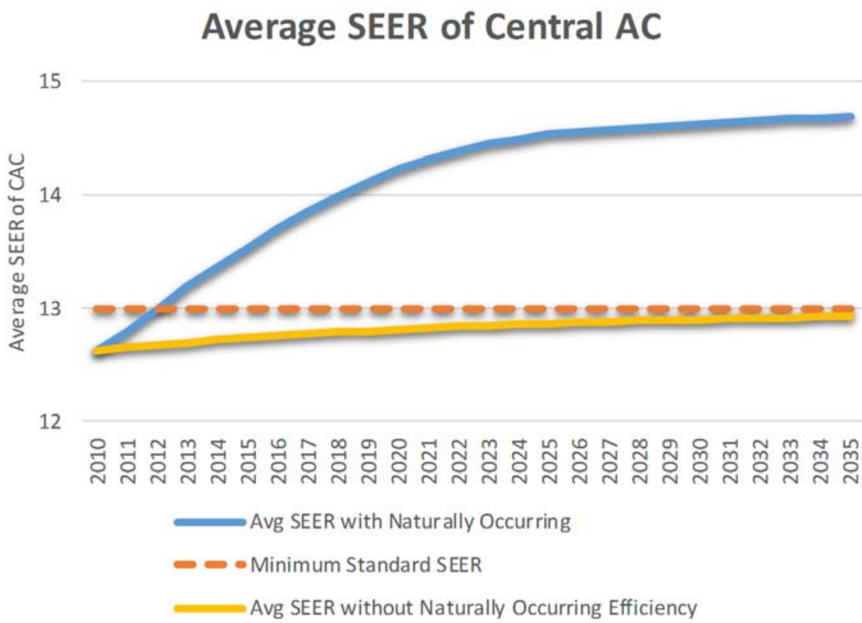
As described above, the SAE models include projections of average end-use appliance efficiency that include naturally occurring efficiency gains. In order to estimate the amount of energy associated with that naturally occurring efficiency, GDS used appliance stock accounting information developed as part of the SAE modeling framework. The average device efficiency curve was recomputed by only allowing all appliance replacements and new appliances in a given year to be purchased at the minimum standard level. The result is a new trend in efficiency that approaches the minimum standard without exceeding it. The new efficiency estimate was then run through the SAE regression modeling to produce the estimated change in end-use energy sales because of the new estimated efficiency without naturally occurring effects.

This section will use Central Air Conditioners (CAC) as an example. In Ameren's SAE modeling, approximately 6% of existing CAC are replaced annually. The number of new units can also be computed by taking the difference in expected market share from one year to the next. To compute the efficiency without naturally occurring effects, the number of replacement and new units are assumed to be added to the system at the standard SEER of 13. This is weighted with the average SEER of the existing stock from the prior year to compute the overall average. Table 5-1 below demonstrates the accounting for a single year. Given replacement rates and projected changes in market share, CAC in 2020 is composed of 56,151 units replaced at 13.00 SEER, 5,365 new units at 13.00 SEER, and 890,675 units still on the system carried forward from 2019 at an average SEER of 12.80. The new weighted average SEER for 2020 with these appliance specifications is 12.82. In the Naturally Occurring Forecast, the average SEER for CAC in 2020 is projected to be 14.23. The difference between the two can be attributed to naturally occurring efficiency. Figure 5-8 shows the entire time series for CAC, demonstrating the Naturally Occurring efficiency projection and the projection in which naturally occurring effects have been removed.

Table 5-1// Appliance Stock Accounting to Remove Effects of Naturally Occurring Efficiency – CAC Example for 2020

Item	Appliance Stock	Average Efficiency
Appliance Stock in 2019	946,826	12.80
Replacement Rate	5.93%	
No. of CAC Replaced in 2020	56,151	13.00
No. of New CAC in 2020	5,365	13.00
Existing Stock Carried Forward	890,675	12.80
Total Stock in 2020	**952,191**	**12.82**
2020 Average Efficiency – No Naturally Occurring		12.82
2020 Average Efficiency – With Naturally Occurring		14.23

Figure 5-8 // CAC Efficiency Curves With and Without Naturally Occurring Efficiency Effects



GDS developed efficiency projections that remove naturally occurring efficiency in a manner similar to the methodology described above for CAC for the following end-uses:

- Central Air Conditioner
- Room Air Conditioner
- Heat Pumps
- Electric Furnaces
- Water Heaters
- Primary and Secondary Refrigerators
- Freezers
- Clothes Washers
- Clothes Dryers
- Dishwashers
- Lighting
- Televisions

5.5 LOAD FORECAST DISAGGREGATION

The baseline forecasts represent projected total energy sales by class. For the potential studies, it is useful to have the forecasts disaggregated in several different ways. This section presents the forecast disaggregation scenarios that will be used by GDS in developing the Potential Study.

5.5.1 Residential

Two forecast breakdowns are useful for preparing the Residential Potential Study. The first is a breakdown of energy by end-use. The SAE modeling framework computes energy sales projections at the end-use level, so the disaggregation for end-use was straightforward. Projected current DSM energy savings were broken down to the end-use level using the 2015 EM&V results. Figure 5-9 shows residential energy sales forecasted by end-use.

Figure 5-9// Residential Energy Sales by End-Use

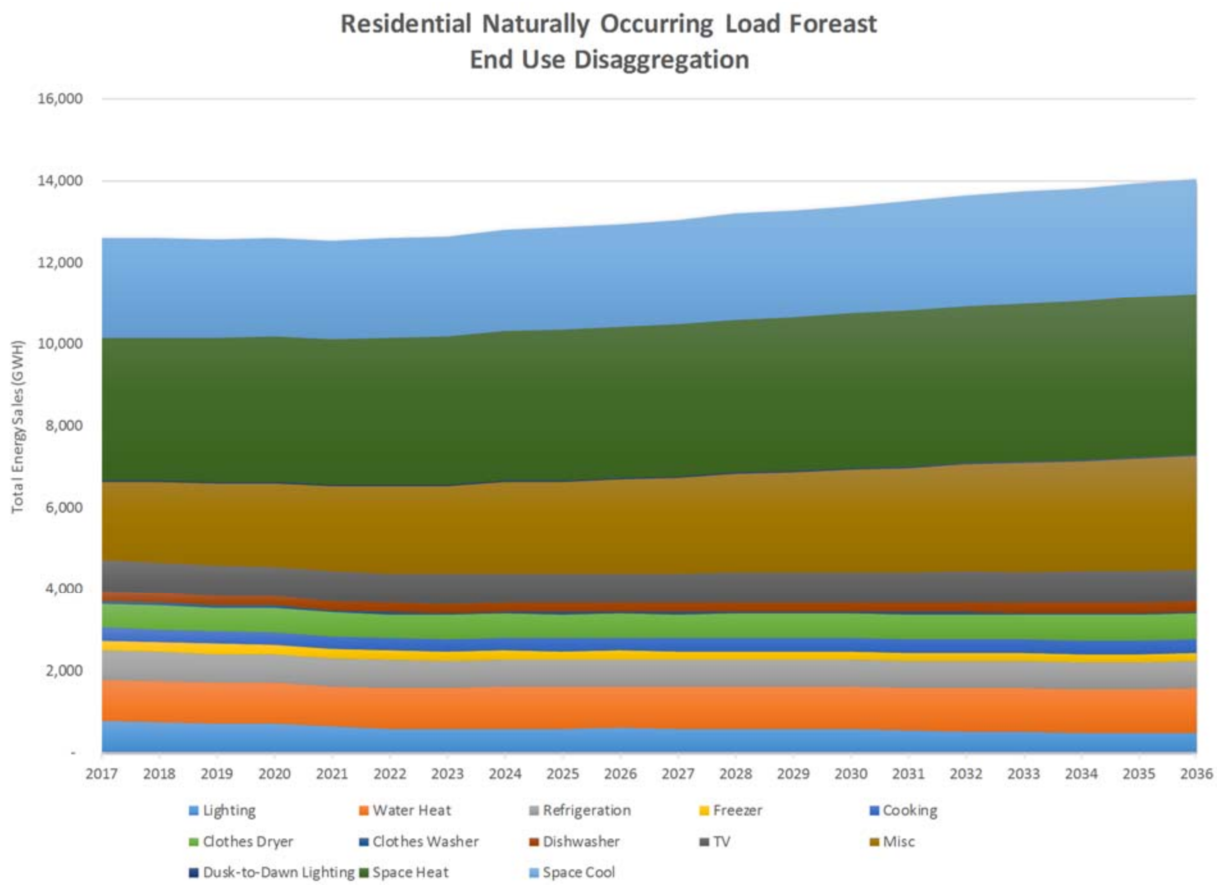
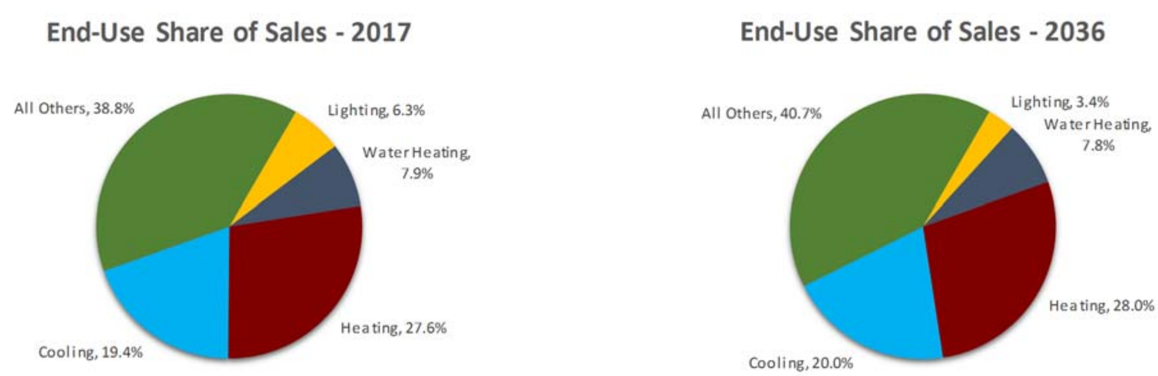


Figure 5-10 below shows the end-use share of major appliances in 2016 and in 2036. Generally, water heating and space conditioning will continue to hold the same relative shares of total energy consumption over the twenty year forecast. The lighting share of residential electricity sales will decline due to EISA and DSM effects and the miscellaneous share will increase with an increasing preponderance of consumer electronics in the home.

Figure 5-10// Major Appliance Share of Residential Sales



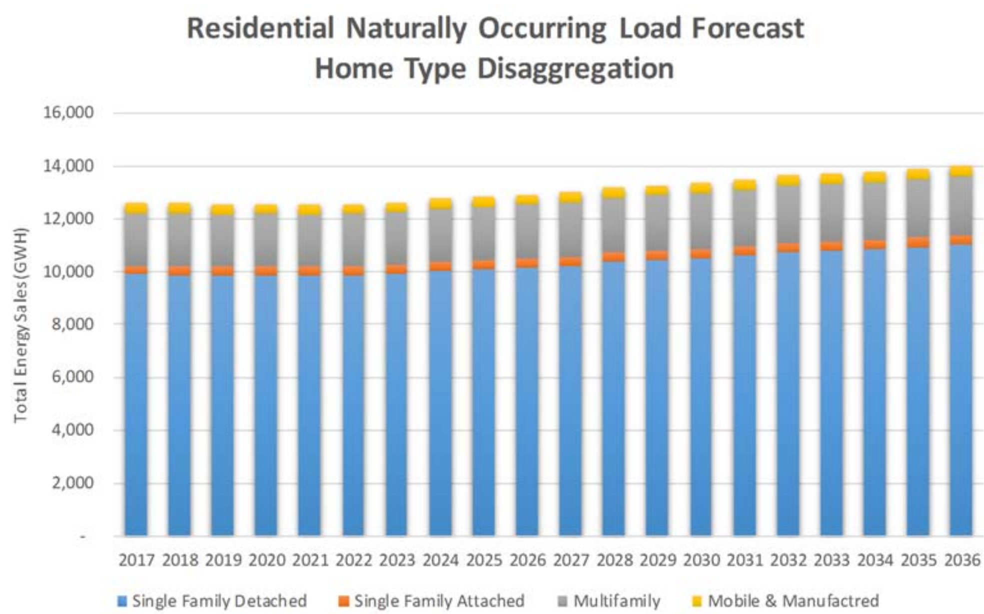
The second type of breakdown needed for the Residential Potential Study is a breakdown of customers and energy sales by home type (Single Family Detached, Single Family Attached, Multifamily, and Mobile\Manufactured Homes). GDS used Census information for each of the zip codes served by Ameren to compute the overall weighted-average share of homes by home type. Zip code census data was weighted by the number of customers served by Ameren in each zip code. The residential consumer forecast was then broken down at these levels to disaggregate the consumer forecast.

Table 5-2// Ameren Homes by Home Type - Census Data by Zip Code

Home Type	Ameren Share
Single Family Attached	68.3%
Single Family Detached	3.5%
Multifamily	25.3%
Mobile Home	2.9%
Total	100.0%

The 2009 RECS data produced by the Census Bureau was used by GDS to estimate the differences in average household consumption by home type. Data for Missouri and the Midwest were used to determine that single family attached homes use approximately 67% of the energy of a single family detached home in Missouri. Likewise, multifamily homes consume 55% of a single family detached home and mobile homes consume 94% of a single family detached home's typical consumption. These estimates were used to determine the share of average household consumption to estimate the energy sales breakdown by home type.

Figure 5-11// Residential Electric Energy Sales by Home Type



5.5.2 Commercial

Commercial energy sales are disaggregated by end-use for the SAE modeling framework. Therefore, it was straightforward to disaggregate the commercial energy sales. In the SAE framework, energy intensity per square foot is estimated for various commercial sectors, such as restaurants, office spaces, or warehouses. These energy intensity estimates come from the EIA AEO and CBECS, an energy survey conducted by the EIA. The share of each sector is derived by using employment data specific to Ameren's territory. In May 2016, the EIA released the data for its latest CBECS study, performed in 2012. The prior CBECS vintage was 2003. GDS updated the SAE model specifications to reflect the newest CBECS data for the Midwest. Figure 5-12 below shows the Commercial Naturally Occurring Forecast disaggregated by end-use and Figure 5-13 demonstrates the change in major end-use share of energy sales from 2017 to 2036. Lighting and HVAC consumption is expected to decline over the next twenty years, office and ventilation share of sales will remain fairly stable, and other miscellaneous uses of energy will increase.

Figure 5-12// Commercial Electric Energy Sales by End Use

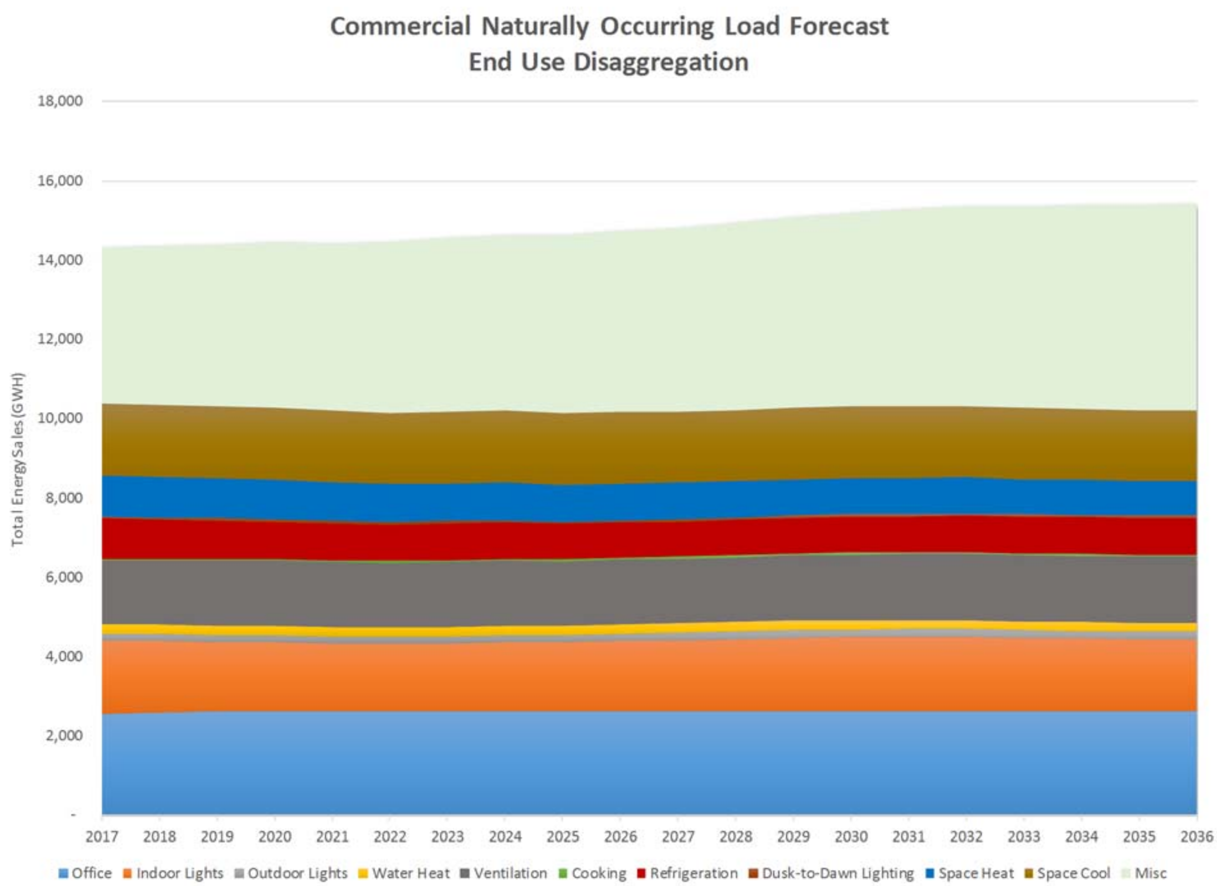
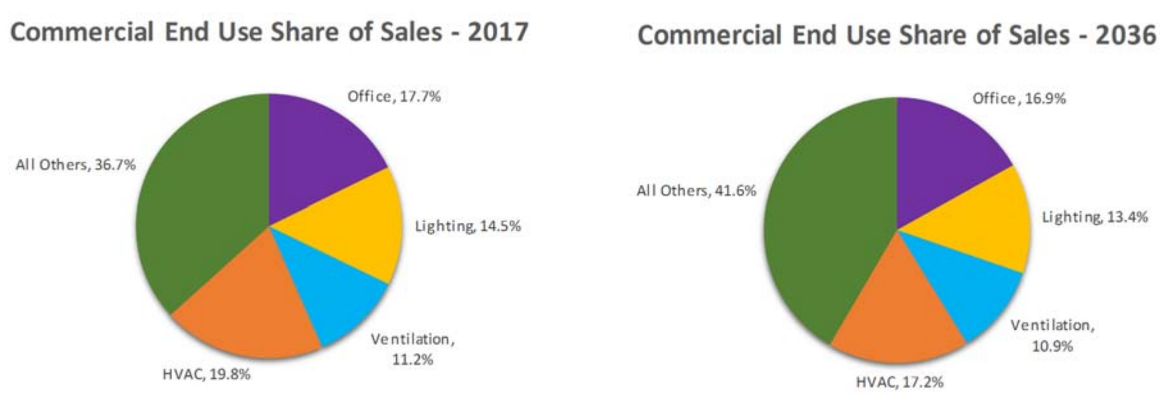


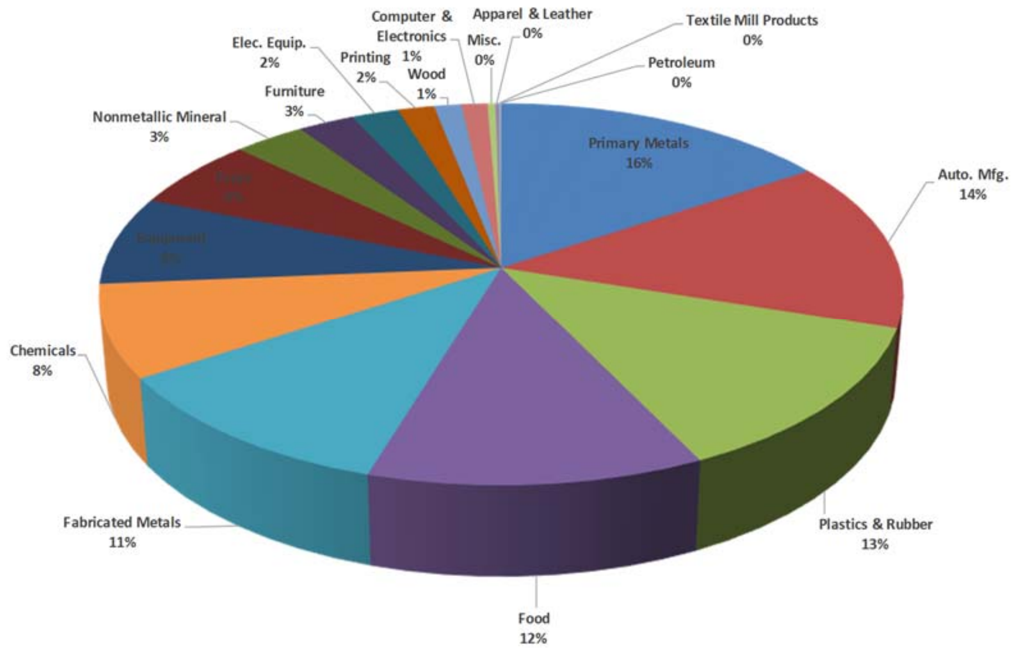
Figure 5-13// End Use Share of Commercial Sales



5.5.3 Industrial

Industrial energy sales are disaggregated by industry sector. GDS obtained industry classification codes for as many commercial and industrial customers as was available from Ameren. We then used those codes and billing history to determine the share of energy sales associated with various industries. Figure 5-14 provides a pie chart showing the Industrial share of electricity sales by industry sector.

Figure 5-14 / / Breakdown of Annual Industrial Sector Electric Sales by Industry Type



5.6 PEAK DEMAND BASELINE

Peak demand forecasts were provided by Ameren by customer classification. GDS used the load factors from the Ameren forecast to apply to the energy baselines to produce coincident peak ("CP") demand baselines by classification. The CP demand represents the contribution of each class to the one-hour Ameren system peak demand. Summer and winter contributions to the Ameren system demand were developed for the residential, commercial, and industrial classifications. Ameren is expected to be a summer peaking system in the future.

In the summer, residential load factors are projected to be 41%. In the winter, the average load factor is 48%. Residential contribution to the Ameren system demand is expected to grow from about 3,500 MW in 2017 to nearly 4,000 MW by 2036.

The commercial class is expected to contribute 2,700 MW to Ameren's peak demand in 2017 and grow to 3,000 MW by 2036. The typical summer load factor is 60% and the typical winter load factor is 70%. The industrial class also has high load factors, 74% in the summer and 88% in the winter. Industrial demand is projected to grow from 700 MW to 770 MW from 2017 to 2036.

Figure 5-15// Residential Class Contribution to System Peak Demand by Season

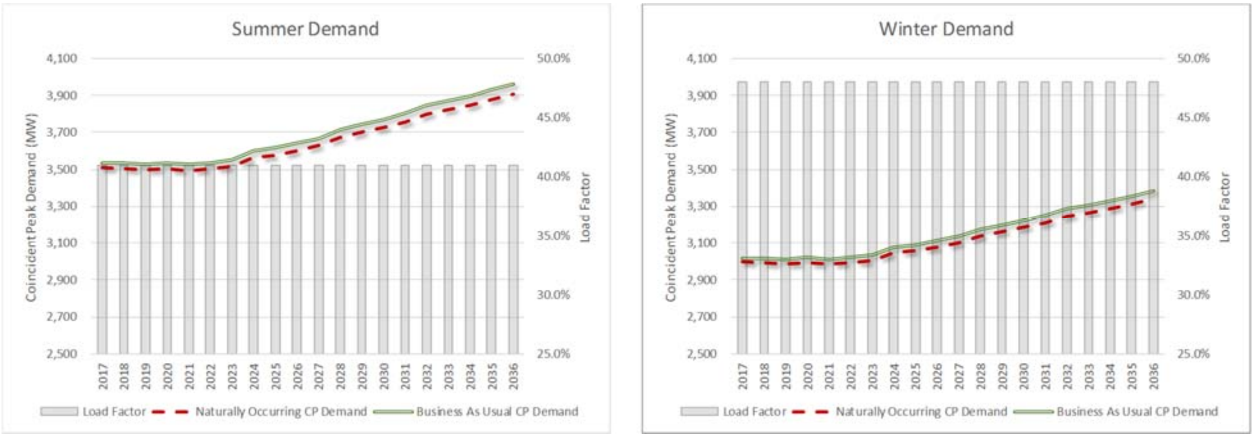


Figure 5-16// Commercial Class Contribution to System Peak Demand by Season

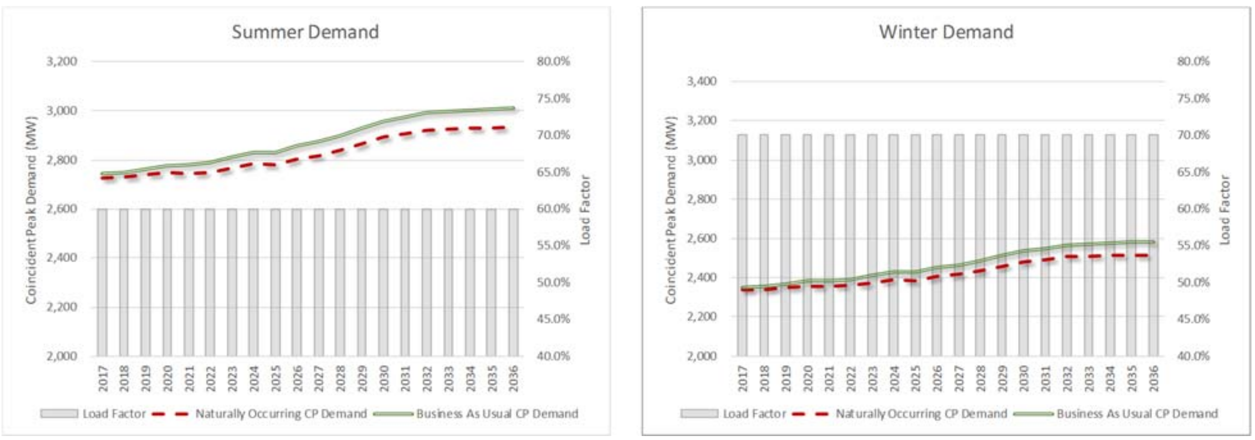
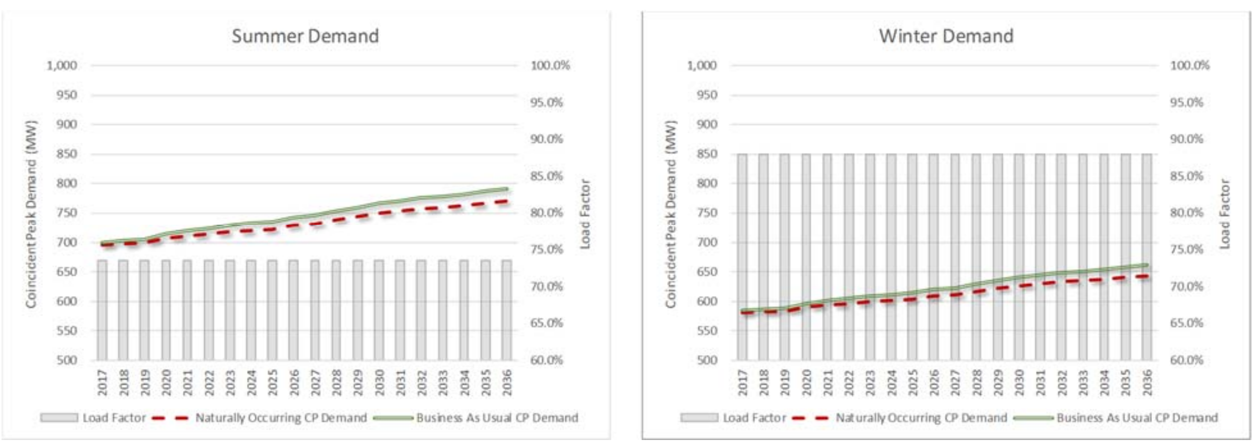


Figure 5-17// Industrial Class Contribution to System Peak Demand by Season



6 ENERGY EFFICIENCY POTENTIAL

6.1 INTRODUCTION

This section of the report assesses the potential for electric energy efficiency programs to assist Ameren Missouri in meeting future electric energy service needs.

The purpose of the electric energy efficiency potential study is to provide a detailed assessment of the technical, economic, achievable and program potential for electric energy efficiency measures for the Ameren Missouri service area. This study has examined a full array of energy efficiency technologies and energy efficient building practices that are technically achievable. The results of this study can be used as a roadmap to develop energy efficiency goals and programs for Ameren Missouri in the short and long-term. The strategies that will be developed based on this potential study can guide the direction and scope of Ameren Missouri administered energy efficiency programs in reducing electricity consumption in the Company's service area.

By conducting this study, Ameren Missouri has adhered to both the Missouri Public Service Commission ("Commission") rules, 4 CSR 240-3.164 regarding potential study requirements for purposes of complying with the Missouri Energy Efficiency Investment Act (MEEIA) and 4 CSR 240-22 regarding potential study requirements for Ameren Missouri's next Integrated Resource Plan (IRP).[17]

6.1.1 Definition of Energy Efficiency

Efficient energy use, often referred to as energy efficiency, is using less energy to provide the same level of energy service. An example would be insulating a home or business to use less heating and cooling energy to achieve the same inside temperature. Another example would be installing LED lighting in place of incandescent, halogen, or fluorescent lightings to attain the same level of illumination. In general, energy efficiency is achievable primarily through more efficient technologies and/or processes rather than by changes in individual behavior.

The **Missouri IRP** rules define demand response options as follows:

***Energy-Efficiency Measure** means any device, technology, or operating procedure that makes it possible to deliver an adequate level and quality of end-use energy service while using less energy than would otherwise be required.[18]*

The **Missouri Energy Efficiency Investment Act** (MEEIA) states:

Energy Efficiency refers to measures that reduce the amount of electricity required to achieve a given end-use.[19]

*A **Demand-Side Program*** is any program conducted by the utility to modify the net consumption of electricity on the retail customer's side of the electric meter, including, but not limited to energy efficiency measures, load management, demand response, and interruptible or curtailable load.[20]

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[17] The Missouri Rules of the Department of Economic Development (4 CSR 240-22) require that electric utilities in Missouri prepare an integrated resource plan (IRP) that "[consider[s] and analyze[s] demand-side efficiency and energy management measures on an equivalent basis with supply-side alternatives in the resource planning process." per Section 4 CSR 240-22.010(2)(A). Section 4 CSR 240-22.050 prescribes the elements of the demand-side analysis, including reporting requirements. A copy of the Missouri rules governing electric utility resource planning is available on the Missouri Secretary of State's website. Details of MEEIA are available on the Missouri Public Service Commission website.

[18] Rules of Department of Economic Development, 4 CSR 240-22.020 (20)

[19] Missouri Energy Efficiency Investment Act, RSMo, Section 393.1075

[20] Missouri Energy Efficiency Investment Act, RSMo, Section 393.1075

6.1.2 Energy Efficiency at Ameren Missouri

Subsequent to the passage of house bill 376 in 2009, the Missouri Energy Efficiency Investment Act known as "MEEIA", Ameren Missouri submitted and was approved for a large initiative to fund Cycle 1 energy efficiency programs beginning in 2013. The MEEIA Cycle 1 programs were administered from 2013 to 2015. The portfolio of programs included seven residential programs and four non-residential programs (or program components) under the BizSavers umbrella. The lighting and HVAC residential programs achieved the largest amount of savings in the final year of Cycle 1, and the low income program was the most successful in 2015 in terms of the program performance compared to the program approved savings target (145% of energy savings target was achieved). The custom program component of BizSavers yielded the most savings of any component in 2015, and the RCx component achieved nearly 1200% of the 2015 goal.

For MEEIA Cycle 2, the residential suite of programs added home energy reports and a giveaway kit program for energy efficient products and removed two programs for no longer being cost effective, the new construction and energy audit programs. Business programs include retro-commissioning, prescriptive rebates, new construction, small business direct install and the custom program which is expected to reap the largest share of anticipated savings with a target of over 197 GWh in the three-year period. Together, the residential and business programs are targeting over 570 GWh of energy savings over the three-year period and 166 MW. Projected budgets are approximately $52 million dollars a year over the three-year period.

6.2 CHARACTERIZATION OF ELECTRICITY USE IN THE AMEREN MISSOURI SERVICE AREA

This section provides a brief recap of historical and forecast information on electricity consumption, and electric customers in Ameren Missouri's service territory. A more thorough discussion of the Ameren forecast and disaggregated forecast results are discussed in Chapter 5. Developing this information is a fundamental part of any energy efficiency potential study. It is necessary to understand how energy is consumed in a utility service area or region before one can assess the energy efficiency savings potential that remains to be tapped.

Customer Segmentation

The first step in this potential study was to segment the market into customer segments that are relevant for analyzing potential, given the available data. The first level of segmentation was by customer class: residential, commercial, and industrial.

Table 6-1 presents the forecasted number of customers by segment in 2019, the forecasted energy sales for each customer segment, and the coincident summer demand for each customer segment. Coincident customer demand refers to the customer load at the time of the system summer peak. The breakdown of customers, energy sales and coincident peak load by segment was developed in conjunction with the baseline forecast. The sales and demand from the baseline forecast are the benchmark against which energy efficiency savings opportunities are measured against. The number of customers is a key component of the residential analysis because the analysis takes a bottom-up approach, whereas in the non-residential analysis the sales forecast is the key component in categorizing savings opportunities using a top-down approach.

Table 6-1// Number of Customers, Sales, and Summer Peak Demand by Class in 2019

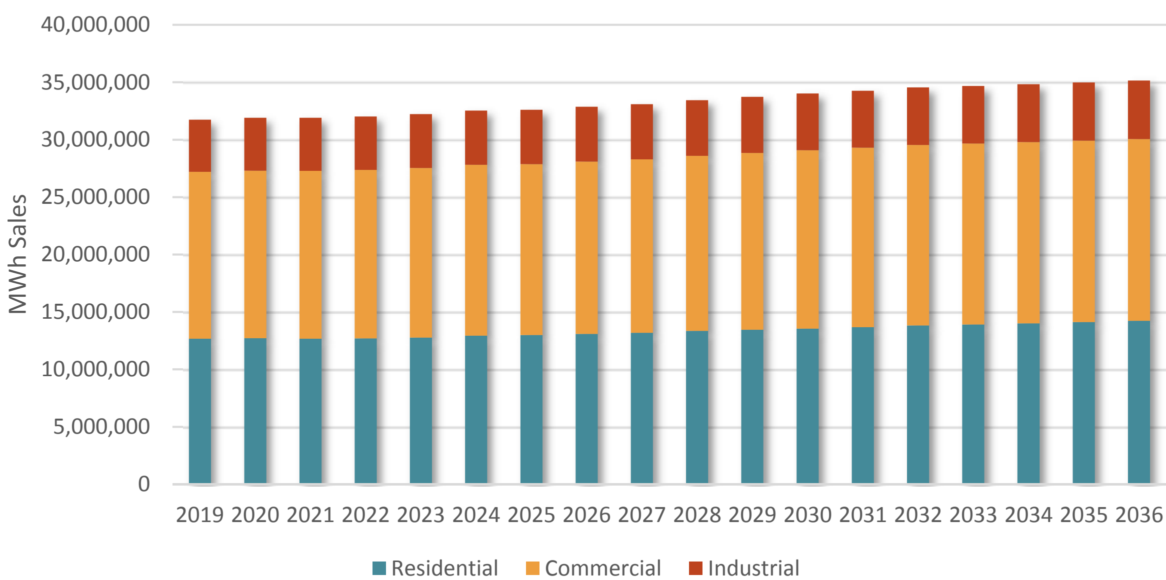
Customer Segment	Number of Customers	Segment Sales (MWh)	Coincident Segment Summer Peak (MW)
Residential	1,054,300	12,670,340	3,528
Commercial	158,039	14,520,362	2,763
Industrial	4,134	4,538,104	705
Total	**1,216,473**	**31,728,806**	**6,995**

Within each customer class, energy sales further segmented by the saturation of end uses that are typically impacted by energy efficiency measures and/or programs. A more detailed description of the customer and end-use load forecast can be found in Chapter 5 of this report.

Sales Forecast

Figure 6-1 and Table 6-2 show the business as usual forecast of electricity sales by sector (in MWh) for the Ameren Missouri service area for the period 2019 to 2036. This Ameren Missouri business as usual load forecast does not include the impact of future DSM efforts. The forecast of annual electric sales for the Ameren Missouri service area shown below do reflect the impacts of historical MEEIA Cycle 1 and Cycle 2 energy efficiency programs.

Figure 6-1// Ameren Missouri Forecast of Annual Electric Sales by Market Segment, 2019-2036 (MWh)



The Ameren Missouri forecast of electricity sales shown in Figure 6-1 above highlights that the Company expects future MWh sales to have minimal growth for the eighteen years, 0.60% per year. The commercial and residential sectors are forecast to have relatively similar shares of annual MWh sales, followed by the industrial sector.

Table 6-2: Ameren Missouri Projected Electric MWh Sales by Sector for 2017 to 2036

Year	Residential Electric Sales (MWh)	Commercial Electric Sales (MWh)	Industrial Electric Sales (MWh)	Total Electric Sales (MWh)
2019	12,670,340	14,520,362	4,538,104	31,728,806
2020	12,700,394	14,597,868	4,597,219	31,895,481
2021	12,661,810	14,611,644	4,628,473	31,901,927
2022	12,700,214	14,656,871	4,658,058	32,015,143
2023	12,756,542	14,768,179	4,693,216	32,217,937
2024	12,927,075	14,884,095	4,713,401	32,524,572
2025	12,985,793	14,879,457	4,731,110	32,596,360
2026	13,077,676	15,011,976	4,778,959	32,868,611
2027	13,178,703	15,103,328	4,799,804	33,081,835
2028	13,344,449	15,237,620	4,848,992	33,431,061
2029	13,441,029	15,393,631	4,891,826	33,726,486
2030	13,545,452	15,532,305	4,933,113	34,010,869
2031	13,667,530	15,625,927	4,963,780	34,257,237
2032	13,818,596	15,723,543	4,998,340	34,540,478
2033	13,903,587	15,751,781	5,013,949	34,669,318
2034	13,995,255	15,784,293	5,038,027	34,817,575
2035	14,109,403	15,807,262	5,065,304	34,981,970
2036	14,223,152	15,829,617	5,092,415	35,145,184

6.3 METHODOLOGY[21]

6.3.1 Overview of Approach

GDS used a bottom-up approach to estimate energy efficiency potential in the residential sector. Bottom-up approaches begin with characterizing the eligible equipment stock, estimating savings and screening for cost-effectiveness first at the measure level, then summing savings at the end-use and service area levels. In the commercial and industrial sectors, the GDS team utilized a top-down modeling approach to first estimate measure-level savings and costs as well as cost-effectiveness, and then applied cost-effective measure savings to all applicable shares of electric energy load. Further details of the data sources and modeling techniques utilized in this assessment are provided in the following sections.

6.3.2 Measure List Development[22]

Energy efficiency measures considered in the study include measures in the 2016 Ameren Missouri Technical Reference Manual as well as other energy efficiency measures based on GDS' knowledge and current databases of electric end-use technologies and energy efficiency measures in other jurisdictions. The study includes measures and practices that are currently commercially available as well as emerging technologies. Emerging technology research was focused on measures that are either commercially available but currently not widely accepted, or are not currently available but expected to be commercialized over the analysis timeframe.[23]

[21] 4 CSR 240-22.050(3)(I)

[22] 4 CSR 240-22.050(3)(C)

[23] For example, an ENERGY STAR criteria was recently established for clothes dryers. High efficiency clothes dryers were included as an emerging technology (these measures are also in the MEMD), even though the commercialization of high efficiency clothes dryers has not become widespread.

In total, GDS analyzed 706 energy efficiency measure types. Many measures required multiple permutations for different applications, such as different building types, efficiency levels, and replacement decision types. GDS developed a total of 12,354 measure permutations for this study, and tested all measures for cost-effectiveness using the TRC Test. The parameters for cost-effectiveness calculations under the TRC are discussed in detail later in this section of the report. Approximately 71% of the measures had a measure TRC benefit-cost ratio of 1.0 or higher.[24]

Table 6-3: Number of Energy Efficiency Measures Evaluated

	# of Measures	Total # of Measure Permutations	# with TRC ≥ 1
By Sector			
Residential	78	789	495
Commercial	367	6,606	4,482
Industrial	261	4,959	3,768
Total	***706***	***12,354***	***8,745***

A complete listing of the energy efficiency measures included in this study is provided in the Appendices of this report.

6.3.3 Energy Efficiency Measure Characterization[25]

A significant amount of data is needed to estimate the kWh and kW savings potential for individual energy efficiency measures or programs across the residential and non-residential sectors in the Ameren Missouri service area. GDS used Ameren Missouri-specific data wherever it was available and reflective of recent updates. Considerable effort was expended to identify, review, and document all available data sources.[26] This review has allowed the development of reasonable and supportable assumptions regarding: measure lives; measure costs (incremental or full costs as appropriate); measure electric savings; and saturations for each energy efficiency measure included in the final list of measures examined in this study.

Savings | Estimates of annual measure savings as a percentage of base equipment usage were developed from a variety of sources, including:

- 2016 Ameren TRM
- Ameren Implementation Database
- Ameren MEEIA Cycle 1 program evaluation report findings
- BEopt™ software modeling – for residential weather-sensitive assumptions
- Illinois TRM
- 2016 Michigan Energy Measures Database
- Secondary sources such as research reports by the American Council for an Energy-Efficient Economy ("ACEEE"), Department of Energy ("DOE"), Energy Information Administration ("EIA"), ENERGY STAR savings calculators, Air Conditioning Contractors of America ("ACCA") and other technical potential studies and Technical Reference Manuals (TRMs)

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[24] The residential included some low income-specific measures with a TRC ratio less than 1.0 in the economic and achievable potential analysis. Low income-specific measures with a UCT ratio of 0.50 or greater were retained in the residential analysis of economic and achievable potential. This approach recognizes that low-income measures and programs may not always be cost-effective, but are offered by utilities to generate savings and address equity concerns.

[25] 4 CSR 240-22.050(1)(D)

[26] The appendices and supporting databases to this report provide the data sources used by GDS to obtain up-to-date data on energy efficiency measure costs, savings, useful lives and saturations.

Measure Costs | Measure costs represent either incremental or full costs, and typically also include the incremental cost of measure installation. For purposes of this study, nominal measures costs were held constant over time. This general assumption is being made due to the fact that historically many measure costs (e.g., CFL bulbs, Energy Star appliances, etc.) have declined over time, while some measure costs have increased over time (e.g., fiberglass insulation). One exception to this assumption will be an assumed decrease in costs for light emitting diode (LED) bulbs. LED bulb consumer costs have been declining rapidly over the last several years and future cost projections predict a continued decrease in bulb costs.[27]

GDS referenced the following data sources for measure cost information:

- Ameren TRM
- Illinois TRM
- Michigan Energy Measures Database (MEMD)
- Secondary sources such as ACEEE, ENERGY STAR, and other technical potential studies and TRMs
- Retail store pricing (such as web sites of Home Depot and Lowe's) and industry experts
- Ameren Missouri program evaluation reports

Costs and savings for new construction and replace on burnout measures are calculated as the incremental difference between the code minimum equipment and the energy efficiency measure. This approach is utilized because the consumer must select an efficiency level that is at least the code minimum equipment when purchasing new equipment. The incremental cost is calculated as the difference between the cost of high efficiency and standard efficiency (code compliant) equipment. However, for retrofit or direct install measures, the measure cost was considered to be the "full" cost of the measure, as the baseline scenario assumes the consumer would not make energy efficiency improvements in the absence of a program. In general, the savings for retrofit measures are calculated as the difference between the energy use of the removed equipment and the energy use of the new high efficiency equipment (until the removed equipment would have reached the end of its useful life).

Measure Life | Represents the number of years that energy-using equipment is expected to operate. Useful life estimates have been obtained from the following data sources:

- Ameren TRM
- Illinois TRM
- MEMD
- Manufacturer data
- Savings calculators and life-cycle cost analyses
- Secondary sources such as ACEEE, ENERGY STAR, and other technical potential studies
- The California Database for Energy Efficient Resources ("DEER") database
- Evaluation reports
- GDS and other consultant research or technical reports

Baseline and Efficient Technology Saturations | In order to assess the amount of electric energy efficiency savings still available, estimates of the current saturation of baseline equipment and energy efficiency measures, or for the non-residential sector the amount of energy use that is associated with a specific end use (such as HVAC) and percent of that energy use that is associated with energy efficient equipment are necessary. Up-to-date measure saturation data were primarily obtained from the following recent studies:

[27] 2014 DOE SSL Multi-Year Program Plan & NEEP Residential Lighting Strategy Report.

- 2013 Ameren potential study market research findings
- MEEIA Cycle 1 program findings
- 2009 EIA Residential Energy Consumption Survey
- 2007 American Housing Survey
- 2010 EIA Manufacturing Energy Consumption Survey (MECS)
- 2012 EIA Commercial Building Energy Consumption Survey (CBECS)

The scope of the potential study did not include updates to the market research used to inform the saturation data estimates in the 2013 potential study. However, for the energy efficient technology saturations, this study did account for the achieved and planned progress associated with MEEIA Cycle 1 and Cycle 2, respectively, in order to attempt to true-up the efficient technology saturations that can be expected to exist starting in 2019.

6.3.4 Treatment of Codes and Standards

Although this analysis does not attempt to predict how energy codes and standards will change over time, the analysis does account for the impacts of several known improvements to federal codes and standards. Although not exhaustive, key adjustments include:

- General Service lighting baselines reflect the minimum efficiency standards and schedule established in the Energy Independence and Security Act of 2007 (EISA 2007). As a result, the baseline efficiency for most general lighting was assumed to be a halogen bulb through May 31, 2020. Beginning in 2021, the analysis reflects the adjustments included in the EISA 2007 backstop provision, and the general service lighting baseline shifts to the CFL bulb. This shift in baseline impacts all bulbs, including those installed prior to 2020.
- The baseline efficiency for air source heat pumps (ASHP) increased to 14 SEER/8.2 HSPF[28] in 2015. As the existing stock of ASHPs was estimated to turn over, the baseline efficiency was assumed to be the new federal standard.
- In 2015, the DOE amended standards effective for residential water heaters that required updated energy factors (EF) depending on the type of water heater and the rated storage volume. For storage tank water heaters with a volume of 55 gallons or less, the new standard (EF=0.948) becomes essentially the equivalent of today's efficient storage tank water heaters.
- In March 2015, the DOE amended the standards for residential clothes washers. The new standards require the Integrated Modified Energy Factor (MEF) (ft3/kWh/cycle) to meet certain thresholds based on the machine configurations. Version 7.0 of the ENERGY STAR specification took effect in March 2015. These amended federal and ENERGY STAR standards have been factored into the MEMD and have thus been accounted for in the study.
- In January 2015, the DOE amended the standards for residential clothes dryers. The new standards require the EF (pounds/kWh) to meet certain thresholds based on the machine configurations. Version 1.0 of the ENERGY STAR specification for residential clothes dryers took effect in January 2015. The DOE-amended standards and the ENERGY STAR specification for residential clothes dryers have been factored into the study.
- In line with the phase-in of 2005 EPAct regulations, the baseline efficiency for general service linear fluorescent lamps was moved from the T12 light bulb to a T8 light bulb.

In addition to accounting for codes and standards in the measure assumptions analysis, the potential study also accounted for codes and standards in the development of the baseline forecast. This allowed the savings assumptions calculations of the energy efficiency analysis to align with the baseline forecast. Refer to Chapter 5 for more detail on the baseline forecast addressed codes and standards.

[28] SEER: Seasonal Energy Efficiency Ratio; HSPF: Heating Seasonal Performance Factor.

6.3.5 Energy Efficiency Potential Assessment Approach[29]

Potential studies often distinguish between several types of energy efficiency potential: technical, economic, achievable, and program. However, because there are often important definitional issues between studies, it is important to understand the definition and scope of each potential estimate as it applies to this analysis. The first two types of potential, technical and economic, provide a theoretical upper bound for energy savings from energy efficiency measures. Still, even the best designed portfolio of programs is unlikely to capture 100 percent of the technical or economic potential. Therefore, achievable and program potential attempts to estimate what may realistically be achieved, when it can be captured, and how much it would cost to do so.

Figure 6-2 illustrates the most common types of energy efficiency potential.

Figure 6-2 // Types of Energy Efficiency Potential[30]

Not Technically Feasible	**Technical Potential**			
Not Technically Feasible	Not Cost-Effective	**Economic Potential**		
Not Technically Feasible	Not Cost-Effective	Market & Adoption Barriers	**Achievable Potential**	
Not Technically Feasible	Not Cost-Effective	Market & Adoption Barriers	Program Delivery Barriers	**Program Potential**

Technical Potential | The theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is only constrained by factors such as technical feasibility and applicability of measures. Under technical potential, GDS assumed that 100% of new construction and burnout measures are adopted as those opportunities become available (e.g., as new buildings are constructed they immediately adopt efficiency measures), while retrofit opportunities are replaced incrementally (10% per year) until 100% of homes (residential) and stock (commercial and industrial) are converted to the efficient measures over a period of 10 years. [31]

In instances where technical reasons do not permit the installation of the efficient equipment in all eligible households or nonresidential facilities an applicability factor is used to limit the potential. The alternative technologies are then utilized to meet the remaining market potential. The applicability factor was also used to delineate between two (or more) competing technologies for the same electrical end use. In the technical potential estimate, priority was given to measures that produced the most savings.[32]

In developing the overall potential electricity savings, the analysis also accounts for the interactive

[29] 4 CSR 240-22.050(5)(G); 4 CSR 240-22.050(1)

[30] Reproduced (with edits) from "Guide to Resource Planning with Energy Efficiency" November 2007. US EPA. Figure 2-1.

[31] Low-income direct install measures were assumed to occur at a rate of 5% annually over the entire 20-year study timeframe.

[32] For estimates of economic and achievable potential, priority was generally assigned to measures that were found to be most cost-effective, according to the UCT Test.

effects of measures designed to impact the same end-use[33]. For instance, if a home or business were to install energy efficient heating and cooling equipment, the overall space heating and cooling consumption in that home would decrease. As a result, the remaining potential for energy savings derived from duct sealing or other building shell equipment would be reduced.

For new construction, energy efficiency measures can be implemented when each new home or building is constructed, thus the rate of availability will be a direct function of the rate of new construction. For existing buildings, energy efficiency potential in the existing stock of buildings will be captured over time through two principal processes:

1) As equipment replacements are made normally in the market when a piece of equipment is at the end of its effective useful life (referred to as "replace-on-burnout" or "turnover" vintage).
2) At any time in the life of the equipment or building (referred to as "retrofit" or "early replacement" vintage).

For the replace-on-burnout measures, the opportunity to replace existing equipment with high efficiency equipment is when equipment fails beyond repair or if the consumer is in the process of building or remodeling. Using this approach, only equipment that needs to be replaced in a given year will be eligible to be upgraded to energy efficient equipment.

For the retrofit measures, savings can theoretically be captured at any time; however, in practice, it takes many years to retrofit an entire stock of buildings, even with the most aggressive of energy efficiency programs

The core equation used in the residential sector energy efficiency technical potential analysis for each individual efficiency measure is shown below.

Equation 6-1// Core Equation for Residential Sector Technical Potential

$$\text{Technical Potential of Efficient Measure} = \text{Total Number of Households} \times \text{Base Case Equipment End Use Intensity} \times \text{Saturation Share} \times \text{Applicability Factor} \times \text{Savings Factor}$$

Where:

- **Total Number of Households** = the number of households in the market segment (e.g. the number of households living in detached single-family buildings)
- **Base Case Equipment End-use Intensity** = the electricity used per customer per year by each base-case technology in each market segment. In other words, the base case equipment end-use intensity is the consumption of the electrical energy using equipment that the efficient technology replaces or affects.
- **Saturation Share** = this variable has two parts: the first is the fraction of the end-use electrical energy that is applicable for the efficient technology in a given market segment. For example, for residential water heating, the saturation share would be the fraction of all residential electric customers that have electric water heating in their household; the second is the share of market for a given end-use (i.e. Electric water heating) that is applicable for the efficient technology that has not yet been converted to an efficient technology.

[33] 4 CSR 240-22.050(3)(G)2

- **Applicability Factor** = the fraction of the applicable units that is technically feasible for conversion to the most efficient available technology from an engineering perspective (e.g., it may not be possible to install CFLs in all light sockets in a home because the CFLs may not fit in every socket).[34]
- **Savings Factor** = the percentage reduction in electricity consumption resulting from the application of the efficient technology.

The core equation utilized in the commercial and industrial sectors technical potential analysis for each individual efficiency measure is shown below.

Equation 6-2// Core Equation for Commercial and Industrial Sector Technical Potential

$$\text{Technical Potential of Efficient Measure} = \text{Total End Use Sales by Industry Type} \times \text{Base Case Factor} \times \text{Remaining Factor} \times \text{Convertible Factor} \times \text{Savings Factor}$$

Where:

- **Total end-use kWh sales by commercial sector and by building type** = the forecasted electric sales level for a given end use (e.g., space heating) in a commercial market segment (e.g., office buildings, wholesale or retail facilities, etc.).
- **Base Case factor** = the fraction of end-use energy applicable for the efficient technology in a given commercial sector type. For example, with fluorescent lighting, this would be the fraction of all lighting kWh in a given commercial building type that is associated with fluorescent fixtures.
- **Remaining factor** = the fraction of applicable kWh sales associated with equipment not yet converted to the electric energy efficiency measure; that is, one minus the fraction of the industry type with energy efficiency measures already installed.
- **Convertible factor** = the fraction of the equipment or practice that is technically feasible for conversion to the efficient technology from an engineering perspective (e.g., it may not be possible to install variable-frequency drives (VFDs) on all motors.
- **Savings factor** = the fraction of electric consumption reduced by application of the efficient technology.

Estimating energy efficiency potential for the industrial sector can be more challenging than it is for the residential and commercial sectors because of the significant differences in the way energy is used across manufacturing industries (or market segments). The auto industry uses energy in a very different manner than does a plastics manufacturer. Further, even within a particular industrial segment, energy use is influenced by the particular processes utilized, past investments in energy efficiency, the age of the facility, and the corporate operating philosophy.

Recognizing the variability of energy use across industry types and the significance of process energy use in the industrial sector, GDS employed a top-down approach that constructed an energy profile based on local economic data, national energy consumption surveys and any available Michigan studies related to industrial energy consumption.

Economic Potential | Refers to the subset of the technical potential that is economically cost-effective (based on screening with the TRC Test) as compared to conventional supply-side energy

[34] In instances where there are two (or more) competing technologies for the same electrical end use, such as heat pump water heaters, water heater efficiency measures, high-efficiency electric storage water heaters and solar water heating systems, an applicability factor aids in determining the proportion of the available population assigned to each measure. In estimating the technical potential, measures with the most savings are given priority for installation. For all other types of potential, measures with the greatest UCT ratio are assigned installation priority.

resources. Both technical and economic potential ignore market barriers to ensuring actual implementation of energy efficiency. Finally, they typically only consider the costs of efficiency measures themselves, ignoring any programmatic costs (e.g., marketing, analysis, administration, program evaluation, etc.) that would be necessary to capture them.

The State of Missouri Revised Statutes, Chapter 393, Section 393.1075.1, states that "The commission shall consider the total resource cost test a preferred cost-effectiveness test."[35] The TRC test calculations in this study follow the prescribed methodology detailed in the latest version of the California Standard Practice Manual (CA SPM). The California Standard Practice Manual establishes standard procedures for cost-effectiveness evaluations for utility-sponsored or public benefits programs and is generally considered to be an authoritative source for defining cost-effectiveness criteria and methodology. This manual is often referenced by many other states and utilities.

The GDS cost effectiveness screening tool used for this study quantifies all of the benefits and costs included in the TRC test. For purposes of this study, quantified benefits of the TRC Test include electric energy and capacity avoided supply costs, and exclude any natural gas or other fossil fuel benefits. GDS has also not included any value for reduced carbon emissions. Costs include all utility and participant costs, any increase in supply costs, as well as any additional operation and maintenance costs. In addition, the GDS screening tool is capable of evaluation of cost-effectiveness based on various market replacement approaches, including replace-on-burnout, retrofit, and early retirement. The forecast of electric avoided costs of energy and generation capacity was obtained from Ameren Missouri.

All measures that were not found to be cost-effective based on the results of the measure-level cost effectiveness screening were excluded from the economic and achievable potential. Applicability factors were then re-adjusted and applied to the remaining measures that were cost effective, where appropriate.

Achievable Potential | Achievable Potential is the cost-effective potential that can practically be attained in a real-world program delivery scenario, assuming that a certain level of market penetration can be attained. Achievable potential takes into account real-world barriers to convincing customers to participate in cost effective programs. Achievable savings potential savings is a subset of economic potential. This potential study evaluates two achievable potential scenarios:

1) **MAP** represents an estimate of the maximum cost-effective energy efficiency potential that can be achieved over the 18-year study period. MAP involves incentives that represents a very high portion of total program costs and very short customer payback periods, and presumes conditions that are ideal and not typically observed. For purposes of this analysis MAP assumed incentives represent 100% of the measure incremental costs.

2) **RAP** represents an estimate of the amount of potential that can be realistically achieved over the 18-year study period. RAP includes incentives that represent a moderate portion of total program costs and longer customer payback periods when compared to those associated with maximum achievable

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[35] The full text for this section of the statute states "The commission shall permit electric corporations to implement commission-approved demand-side programs proposed pursuant to this section with a goal of achieving all cost-effective demand-side savings. Recovery for such programs shall not be permitted unless the programs are approved by the commission, result in energy or demand savings and are beneficial to all customers in the customer class in which the programs are proposed, regardless of whether the programs are utilized by all customers. The commission shall consider the total resource cost test a preferred cost-effectiveness test. Programs targeted to low-income customers or general education campaigns do not need to meet a cost-effectiveness test, so long as the commission determines that the program or campaign is in the public interest. Nothing herein shall preclude the approval of demand-side programs that do not meet the test if the costs of the program above the level determined to be cost-effective are funded by the customers participating in the program or through tax or other governmental credits or incentives specifically designed for that purpose."

potential. For purposes of this analysis, incentives levels for RAP were consistent with the historical incentive levels established during MEEIA Cycle 1 and Cycle 2.

While many different incentive scenarios could be modeled, the number of achievable potential scenarios that could be developed was limited to two scenarios due to the available budget for this potential study[36]. In addition to the MAP and RAP potential, GDS also developed estimates of program potential.

Program Potential includes the allocation and bundling of individual measures into specific program concepts to support Ameren Missouri's program planning process. Cost-effective measures were bundled into programs based on a mapping to existing Ameren Missouri programs or new programs, if necessary. Measures that are in the achievable potential but excluded from program potential include those for which the efficiency market has already largely transformed (televisions), measures which have shown to achieve poor realization rates or very low participation in other jurisdictions. Program potential also incorporates NTG considerations, and excludes measures with low NTG ratios. Program potential cases were created based on the RAP and MAP achievable potentials.

6.3.6 Customer Participation

The assumed level of customer participation (take rate) for each energy efficiency measure is a key driver of achievable potential estimates. In an effort to inform estimates of future market adoption, the GDS Team relied on both the historical achievements of Ameren Missouri in prior years, as well as the adjusted take rate research completed by EMI and discussed in a prior section of this report. The historical benchmarking estimated an initial "ground floor" market adoption rate while the adjusted take rate analysis formed the basis of the long-term market adoption values.

Initial Year Measure Adoption

For estimates of RAP, initial year measure adoption was derived based on the latest estimates of energy efficiency saturation levels in the Ameren Missouri service area, and the achieved participation from MEEIA Cycle 1 and 2. In general, the latest primary research on Ameren Missouri efficient equipment saturation levels was conducted in 2013 as part of the prior potential study. Using these estimates as a starting point, GDS adjusted efficiency saturation levels to reflect the historical achievements of MEEIA Cycle 1 and the projected participation from MEEIA Cycle 2. For example, 3% of lighting sockets in the residential sector were assumed to be equipped with LEDs in 2013. After accounting for the impacts of Ameren's 2013-2018 programs, the percent of LED lighting increased to 12%. The GDS Team assumed this value as the initial year market adoption rate for most measures so that 2019-2036 efficiency saturation levels would continue to meet or exceed historical levels.

A second step in the initial year measure adoption rate analysis was to calibrate initial year potential to historical levels. In an iterative process, GDS reviewed the initial estimates of RAP in 2019 to ensure that estimates of energy potential and annual costs were not below, or significantly above, current historical levels. If significant differences were observed, GDS would scale the initial year adoption estimates up or down to align with the historical realities of prior year program participation.

For estimates of MAP, the initial year measure adoption rate was set equal to the long term market adoption rate (or take rates) to reflect that the most aggressive incentive levels, program delivery methods, and other conditions would remove barriers to market adoption allowing initial year market adoption to equal the longer-term values.

[36] 4 CSR 240-22.050(3)(G)5B

Take Rates (Long-Term Market Adoption)

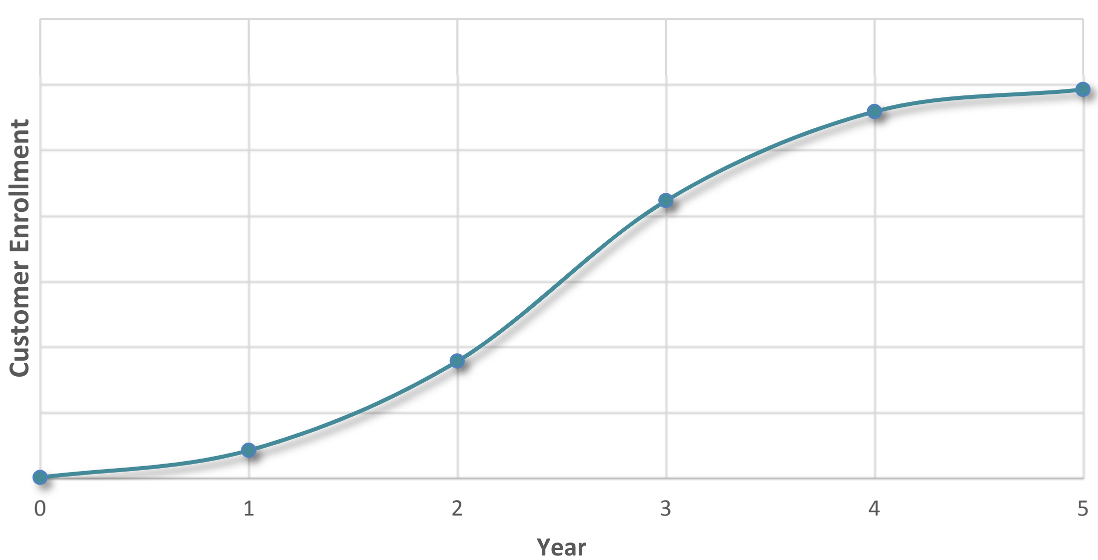
Estimating future market adoption of energy efficient technologies is a difficult and uncertain practice. In an effort to inform these estimates, the GDS/EMI Team reviewed and adjusted the take rate values derived as part of the 2013 potential study to reflect the most recent observed market trends regarding program participation rates from programs in the Midwest and nationally. Discussed in Chapter 4 of this report, this analysis produced estimated long term market adoption rates (or take rates) based on an efficiency measures estimated simple payback. The steady state long-term market adoption rate represents the enrollment rate once the fully achievable participation has been reached. Take rates are expressed as a percentage of eligible annual measures that would receive energy-efficient installations.

For estimates of MAP, incentives were assumed to be equal to 100% of the measure cost, and payback for all measures was immediate. As a result, the most aggressive take rate was assumed for each measure in the MAP analysis.

For estimating realistic achievable potential and program RAP, the calculated simple payback for each measure was dependent on the assumed incentive levels in the RAP scenario (discussed further below). Simple payback levels were mapped to the 1-year, 3-year and 5-year take rates produced as part of the adjusted take rate analysis. Measures with estimated payback longer than 5-years were mapped to the 5-year take rate with no further adjustment. In select instances, including low income-specific measures where Ameren would pay incentives equal to the measure cost, current incentive levels produced a payback period of 1-year or less, resulting in little to no difference in the take rates between MAP and RAP.

Finally, measure adoption was assumed to increase, from the initial year market adoption rate and reach the steady state long-term market adoption rate over a multi-year period, dependent on the payback period. Measures with a shorter payback period were assumed to reach the steady state long-term market adoption rate sooner than measures with longer payback. The path to steady state customer participation follows an "S-shaped" curve, in which participation growth accelerates over the first half of the determined time period, and then slows over the second half of the period (see Figure 6-3).

Figure 6-3// Illustration of S-Shaped Market Adoption Curve



6.3.7 Program Costs

GDS conducted a review of available information pertaining to Ameren Missouri's evaluated energy efficiency program performance. GDS reviewed each of Ameren's filed annual evaluation reports and collected various data points including Ameren expenditures and participant costs to establish benchmarking data on Ameren's performance of their DSM programs under MEEIA. Metrics tracked included:

- Net Energy Savings
- Incentive expenditures as a percentage of incremental measure costs
- Administrative cost ($ per 1st-year kWh saved)

The purpose of this step was to understand historical program delivery performance, and to help inform estimates of maximum and realistic achievable potential. Table 6-4 summarizes the observed residential incentive and program administrative cost trends observed for the Ameren Missouri territory and applied to the residential sector analysis. The incentive cost assumptions below were applied in the RAP and program RAP scenarios. MAP and program MAP assumed that incentives are equal to 100% of incremental measure cost.

Table 6-4// Program Cost Assumptions

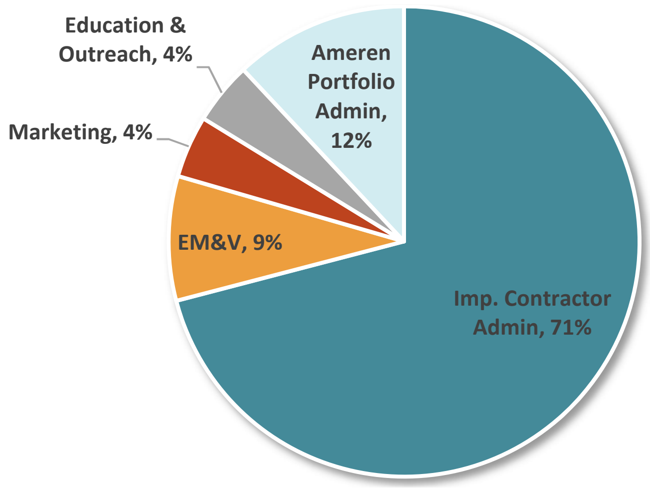
Measure/Program Type	Incentive (as a % of Measure Cost)	Program Administrative Costs ($/1-st Year kWh)
Lighting	50%	$0.022
Efficient Products	50%	$0.113
HVAC	35%	$0.097
Home Energy Analysis (Building Shell)	60%	$0.398
Low Income	100%	$0.163
Appliance Recycling	100%	$0.624

For the commercial and industrial sectors, RAP and program RAP incentives were set at 50% of measure costs as a proxy for typical incentives across a variety of end uses and program delivery types. This assumption is consistent with other recent regional potential studies such as the 2013 KCPL analysis[37]. Similar to the residential sector, MAP assumed that incentive costs were equal to 100% of the measure cost. The administrative costs were determined based on discussions with Ameren regarding historical and projected non-residential program costs and are assumed to be 50% of total utility costs.

Last, once total program and portfolio administrative costs were calculated, GDS coordinated with Ameren Missouri to develop detailed administrative budget categories and breakdowns. These administrative budget categories include: implementation contractor costs, EM&V, Marketing, Education & Outreach, and Ameren-related portfolio administration.[38] Figure 6-4 provides the allocation breakdown of these administrative costs.

Figure 6-4// Administrative Budget Allocation Breakdown

[37] Demand-Side Resource Potential Study Report, prepared for Kansas City Power and Light. 2013. Pg. 41.
[38] Includes R&D, potential studies, and related expenses, but exclude Ameren labor costs.



6.4 TECHNICAL, ECONOMIC, ACHIEVABLE, PROGRAM POTENTIAL RESULTS BY SECTOR[39]

This section provides the potential results for technical, economic, MAP, RAP, Program MAP, and Program RAP for each customer sector. The cost-effectiveness results for MAP, RAP, Program MAP, and Program RAP are also provided.

6.4.1 Residential Energy Efficiency Potential

Measures Examined

For the residential sector, there were 819 total electric savings measures included in the potential energy savings analysis[40]. Table 6-5 provides a brief description of the types of measures included for each end use in the residential model. The list of measures was developed based on a review of the Ameren TRM, the Illinois TRM, the MEMD, feedback from Ameren and other stakeholders, and measures found in other residential potential studies and TRMs from the Midwest. Measure data includes incremental costs[41], electric energy and demand savings, natural gas savings, and measure life.

Table 6-5// Measures and Included in the Electric Residential Sector Analysis

End-Use	Measures Included
HVAC	Dirty filter alarm
	Heat pump tune-up
	Packaged terminal heat pump
	Geothermal heat pump
	Desuperheater
	Heat pump strip
	High efficiency bathroom exhaust fan
	Indoor/outdoor coil cleaning
	Learning thermostat
	Setback thermostat
	Smart thermostat

[39] 4 CSR 240-22.050(1)(A); 4 CSR 240-22.050(1)(B); 4 CSR 240-22.050(3)(C); 4 CSR 240-22.050(3)(D)
[40] This total represents the number of unique electric energy efficiency measures and all permutations of these unique measures. For example, there are 16 permutations of the ENERGY STAR Clothes Washer measure to account for the various housing types, water heating type and presence and fuel type of dryers.
[41] 4 CSR 240-22.050(3)(G)5A

End-Use	Measures Included
	Three-function heat pump (hot water, heating, cooling)
	Air source heat pump (15 to 21 SEER)
	Dual fuel heat pump
	Ductless heat pump
	ECM Fan
Lighting	Standard LED
	Specialty LED
	Specialty CFL
	LED reflectors
	T8 linear fluorescent bulb
	LED Nightlights
	Residential Occupancy Sensors
Building Shell	Air sealing
	Ceiling insulation
	Duct insulation
	Duct repair
	Duct sealing
	Cool roof
	Radiant barrier
	Wall insulation
	Insulated cellular shades
	Shade trees
	Window film
	Window replacement
	ENERGY STAR door
	Floor insulation
	Basement wall insulation
	Crawlspace wall insulation
Appliances / Electronics	ENERGY STAR 6.0 TV (31-40")
	Advanced Power Strip Tier 2 - entertainment center
	Smart residential outlet
	Smart Strip - motion sensing
	Smart Strip - load sensing
	Efficient set top box
	Dehumidifier recycling
	Efficient sound bars
	ENERGY STAR display monitor
	ENERGY STAR laptop
	ENERGY STAR PC

End-Use	Measures Included
	ENERGY STAR dehumidifier
	Energy Star air purifier
	Energy Star water cooler
Space Cooling	AC Tune-up / refrigerant charge
	Packaged terminal air conditioner
	Room AC recycling
	ENERGY STAR room air conditioner
	Ductless air conditioner
	Central air conditioner (SEER 14 through 21)
Water Heating	Pipe insulation
	Low flow faucet aerator
	Low flow showerhead
	Shower start 1.5 gpm electric water heater
	TubSpout with showerhead 1.5 GPM, electric DHW
	Water heater, tank blanket-insulation - electric
	Gravity film heat exchanger GFX electric water heater
	Heat pump water heaters
	Solar domestic hot water - electric water heater
Refrigeration	ENERGY STAR refrigerator
	Refrigerator recycling
	Refrigerator coil cleaning brush
Clothes Washer	ENERGY STAR clothes washers
Pool/Spa	Pool pump and motor single speed
	Pool pump and motor with auto controls - multi speed
	VFDs on residential swimming pool pumps
Freezer	ENERGY STAR Freezer
	Freezer recycling
Dishwasher	ENERGY STAR dishwasher - electric water heater
Clothes Dryer	ENERGY STAR electric clothes dryers
	Heat pump clothes dryer
	ENERGY STAR gas clothes dryers

Technical, Economic, and Achievable Potential

Table 6-6 and Table 6-7 show the cumulative annual technical, economic, maximum achievable (MAP), and realistic achievable (RAP) energy and demand potential in the residential sector in 2019, 2020, 2021, 2028 and 2036. These values are at the customer meter and do not include any net-to-gross assumptions. Figure 6-5 shows the residential energy efficiency potential as a percent of the residential sales forecast.

Table 6-6// Summary of Cumulative Annual Residential Technical, Economic, and Achievable Energy (MWh) Potential

Potential Level	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
Technical	650,284	1,284,892	1,677,268	4,596,332	6,178,604
Economic	524,734	1,037,816	1,314,264	3,621,851	4,901,574
MAP	272,061	540,834	666,107	1,891,187	2,610,006
RAP	101,084	283,202	429,743	1,563,523	2,251,847

Table 6-7// Summary of Cumulative Annual Residential Technical, Economic, and Achievable Peak Demand (MW) Potential

Potential Level	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Technical	129	255	354	868	1,091
Economic	99	196	269	669	840
MAP	50	99	133	340	449
RAP	21	55	89	285	381

Figure 6-5// Summary of Cumulative Annual Residential Electric Energy Savings Potential as a % of Residential Forecast Sales

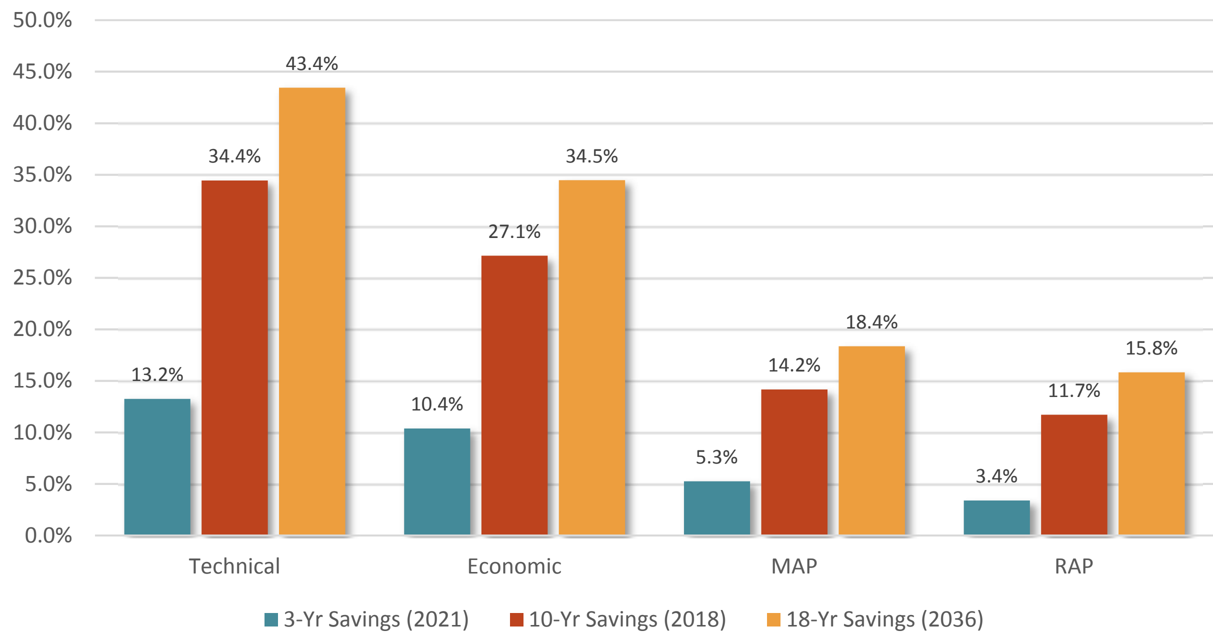


Table 6-8 through Table 6-11 show the residential technical, economic, maximum and realistic achievable energy efficiency potential by end-use for the years 2019, 2020, 2021, 2028, and 2036. HVAC equipment, building shell opportunities represent the top three end-uses for in each scenario. Lighting opportunities are associated with specialty bulbs not impacted by EISA. The HVAC equipment and building shell uses have savings opportunities from a mix of technologies such as high performance heat pumps and comprehensive air sealing and insulation measures.

Table 6-8// Summary of Cumulative Annual Residential Energy (MWh) Technical Potential Savings by End-Use[42]

End-Use	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
HVAC	167,754	331,361	491,009	1,260,254	1,841,212
Building Shell	101,679	196,559	285,054	797,859	1,162,547
Lighting	166,565	330,772	267,116	821,478	1,017,894

[42] 4 CSR 240-22.050(3)(G)1

End-Use	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
Water Heating	57,060	112,294	165,765	492,159	657,046
Appliances / Electronics	72,458	144,656	216,672	462,239	496,967
Space Cooling	30,023	59,914	89,711	279,460	447,171
Refrigeration	19,458	38,900	56,448	141,085	159,564
Clothes Dryer	9,517	18,989	28,431	94,062	132,152
Pool/Spa	11,256	22,465	33,641	111,386	112,812
Clothes Washer	9,120	18,208	27,273	90,389	100,257
Freezer	3,598	7,191	10,781	28,187	32,989
Dishwasher	1,795	3,584	5,367	17,775	17,992
Total	**650,284**	**1,284,892**	**1,677,268**	**4,596,332**	**6,178,604**

Table 6-9// Summary of Cumulative Annual Residential Energy (MWh) Economic Potential Savings by End-Use

End-Use	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
HVAC	153,416	303,309	449,866	1,214,729	1,806,459
Lighting	150,892	299,478	220,239	681,234	854,091
Building Shell	66,971	129,891	188,994	532,761	805,851
Appliances / Electronics	62,730	125,247	187,614	413,868	447,172
Space Cooling	25,733	51,466	77,199	242,363	382,085
Water Heating	22,999	44,541	64,647	165,241	203,058
Refrigeration	17,161	34,307	51,442	133,187	148,362
Pool/Spa	11,256	22,465	33,641	111,386	112,812
Clothes Washer	8,944	17,856	26,745	88,640	98,316
Freezer	3,598	7,191	10,781	28,187	32,989
Dishwasher	1,036	2,067	3,096	10,255	10,378
Clothes Dryer	0	0	0	0	0
Total	**524,734**	**1,037,816**	**1,314,264**	**3,621,851**	**4,901,574**

Table 6-10// Summary of Cumulative Annual Maximum Achievable Residential Energy (MWh) Savings by End-Use

End-Use	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
HVAC	76,244	151,928	227,089	634,215	953,379
Lighting	93,892	186,350	137,035	423,923	531,854
Building Shell	26,798	52,792	78,012	239,859	391,786
Appliances / Electronics	32,669	65,235	97,728	211,535	227,582
Space Cooling	12,780	25,560	38,340	120,496	191,136
Water Heating	10,478	20,624	30,447	90,086	125,319
Refrigeration	6,782	13,555	20,321	51,879	60,824
Clothes Washer	4,906	9,795	14,671	48,621	53,934
Pool/Spa	5,178	10,334	15,475	51,237	51,894
Freezer	1,798	3,594	5,387	14,026	16,930
Dishwasher	536	1,070	1,602	5,309	5,369
Clothes Dryer	0	0	0	0	0
Total	**272,061**	**540,834**	**666,107**	**1,891,187**	**2,610,006**

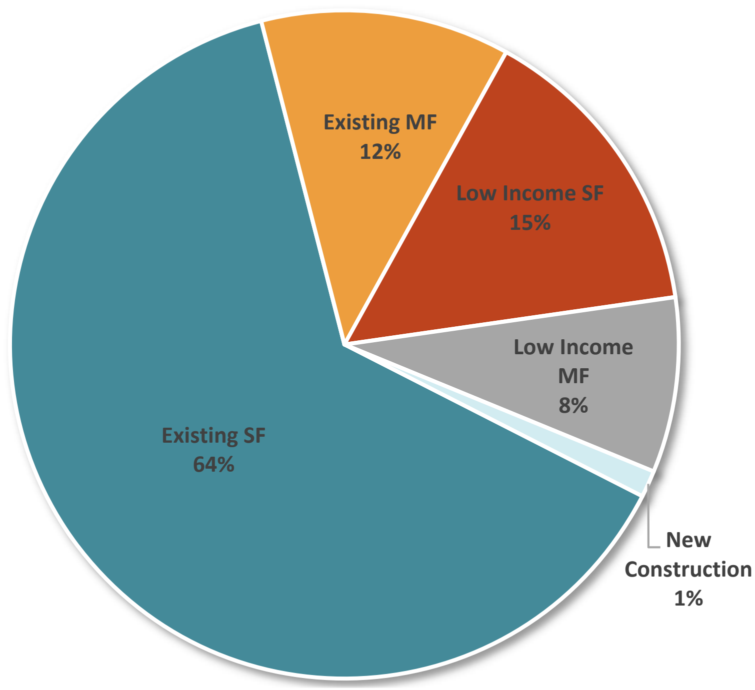
Table 6-11// Summary of Cumulative Annual Realistic Achievable Residential Energy (MWh) Savings by Program

End-Use	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
HVAC	22,608	72,187	137,731	516,217	822,020
Lighting	25,919	84,555	78,812	338,430	441,654
Building Shell	9,487	27,805	51,045	204,581	351,927
Appliances / Electronics	21,122	47,122	75,922	186,739	200,457
Space Cooling	7,475	16,334	26,051	95,935	157,014
Water Heating	2,638	8,028	15,649	68,675	108,261
Refrigeration	3,145	8,318	14,678	48,843	56,704
Clothes Washer	2,944	6,721	10,977	40,607	47,066
Pool/Spa	4,561	9,161	13,775	45,880	46,544
Freezer	672	1,929	3,526	12,299	14,794
Dishwasher	513	1,041	1,578	5,316	5,406

End-Use	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
Clothes Dryer	0	0	0	0	0
Total	**101,084**	**283,202**	**429,743**	**1,563,523**	**2,251,847**

Figure 6-6 provides a breakdown of the residential RAP savings by several market segments on a cumulative annual basis by 2036. The RAP savings are mostly attributable to non-income specific energy efficiency measures applicable to existing single-family (64%) and multifamily (12%) homes. There is also a portion of the RAP savings attributable to low-income specific measures applicable to existing single-family (15%) and multifamily (8%) homes. Measures specifically applicable to new construction opportunities represent 1% of residential RAP savings.

Figure 6-6// 2036 Cumulative Annual Realistic Achievable Potential by Residential Market Segment



Program MAP and RAP Potential

Table 6-12 and Table 6-13 show the residential program MAP and RAP potential for each program for the years 2019, 2020, 2021, 2028, and 2036. Program potential is a subset of measure level MAP and RAP to account for measure mapping, NTG impacts, and historical activity. For the residential sector, the analysis eliminated measures with low NTG ratio estimates, or where market is largely transformed (i.e. ENERGY STAR TV's, and also eliminated measures where EM&V or poor performance suggests limited applications (i.e. ceiling insulation where a considerable amount of insulation already exists; wall insulation in existing home; residential PTAC units) and participation estimates for the first year of the analysis were also calibrated to historical levels.

Table 6-12// Summary of Cumulative Annual Residential Program MAP Energy (MWh) Savings by Program

Program	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
HVAC Program	70,842	141,291	211,384	655,224	1,091,737
Low Income Program - SF	28,430	56,286	67,544	211,592	365,250
Efficient Products Program	33,410	66,881	100,445	304,408	359,954
Lighting Program	66,608	132,296	94,055	279,549	288,696
Low Income Program - MF	13,884	27,489	34,079	106,774	184,311
Energy Efficiency Kits Program	3,884	7,633	11,250	32,728	39,102
Appliance Recycling Program	3,918	7,836	11,753	31,342	31,342
Total	**220,975**	**439,712**	**530,511**	**1,621,616**	**2,360,392**

Table 6-13// Summary of Cumulative Annual Residential Program RAP Energy (MWh) Savings by End-Use

Program	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
HVAC Program	23,592	70,804	132,092	537,615	936,741
Low Income Program - SF	9,578	28,478	42,784	172,260	309,243
Efficient Products Program	14,104	29,920	47,469	215,605	295,975
Lighting Program	17,259	58,202	52,573	224,294	241,686
Low Income Program - MF	5,374	15,983	25,037	100,528	179,477
Energy Efficiency Kits Program	1,337	3,975	7,331	28,335	36,519
Appliance Recycling Program	1,527	4,572	8,501	31,431	31,431
Total	**72,771**	**211,934**	**315,787**	**1,310,068**	**2,031,073**

Program Cost-Effectiveness

Table 6-14 and Table 6-15 show the MAP and RAP residential net present values of the total benefits, costs, and savings, along with the TRC ratio for each program.

Table 6-14// Residential Program MAP NPV Benefits, Costs, Savings, and TRC Ratios by Program ($, in millions)

Program	NPV Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
HVAC Program	$1,011.9	$389.1	$622.8	2.6
Low Income Program - SF	$383.6	$385.4	-$1.8	1.0
Efficient Products Program	$350.8	$178.9	$171.8	2.0
Lighting Program	$276.3	$87.9	$188.4	3.1
Low Income Program - MF	$188.9	$166.0	$22.9	1.1
Energy Efficiency Kits Program	$42.2	$6.8	$35.4	6.2
Appliance Recycling Program	$37.6	$13.0	$24.6	2.9
Total	**$2,291**	**$1,227**	**$1,064**	**1.9**

Table 6-15// Residential RAP NPV Benefits, Costs, Savings, and TRC Ratios by Program ($, in millions)

Program	NPV Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
HVAC Program	$846.6	$316.1	$530.5	2.7
Low Income Program - SF	$313.1	$303.8	$9.3	1.0
Efficient Products Program	$261.1	$115.5	$145.6	2.3
Lighting Program	$223.3	$60.3	$162.9	3.7
Low Income Program - MF	$178.5	$151.8	$26.7	1.2
Energy Efficiency Kits Program	$36.8	$5.7	$31.1	6.5
Appliance Recycling Program	$35.8	$12.1	$23.7	3.0
Total	**$1,895**	**$965**	**$930**	**2.0**

6.4.2 Commercial Energy Efficiency Potential

Measures Examined

For the commercial sector, there were 367 total electric savings measures included in the potential energy savings analysis. Table 6-16 provides a brief description of the types of measures included for each end use in the commercial model. The list of measures was developed based on a review of the Ameren Implementation Database, the latest MEMD, and measures found in other TRMs and commercial potential studies. Measure data includes incremental costs, electric energy and demand savings, natural gas savings, and measure life.

Table 6-16: Measures Included in the Electric Commercial Sector Analysis

End Use Type	End Use Description	Measures Included
Office Equipment	Office Equipment Improvements	– Appliances – High Efficiency Office Equipment – Smart Power Strips – Computer Energy Management Controls – Computer Room Upgrades
Compressed Air	Compressor Equipment	– Efficient Air Compressors – Automatic Drains – Cycling and High Efficiency Dryers – Low Pressure Drop-Filters – Air-Entraining Air Nozzles – Receiver Capacity Addition – Compressed Air Audits, Leak Repair, and Flow Control – Suction Line Insulation
Cooking	Cooking Equipment Improvements	– Efficient Cooking Equipment
Envelope	Space Heating and Space Cooling	– Building Envelope Improvements – Cool Roofing – Integrated Building Design
HVAC Controls	Space Cooling and Space Heating	– Programmable Thermostats – EMS Installation/Optimization – Hotel Guest Room Occupancy Control System – Retro-commissioning & Commissioning
Lighting	Lighting Improvements	– Efficient Lighting Equipment – Fixture Retrofits – Ballast Replacement – Premium Efficiency T8 and T5 – High Bay Lighting Equipment – LED Bulbs and Fixtures

End Use Type	End Use Description	Measures Included
		– Light Tube – Lighting Controls – Efficient Design for New Construction – LED Traffic Signals and Street Lighting
Other	Transformer Equipment / Other	– Efficient Transformers – Optimized Snow and Ice Melt Controls – EC Plug Fans in Data Centers – Engine Block Heater Timer – High Efficiency Elevators
Pools	Pool Equipment	– Efficient Equipment and Controls – Heat Pump Pool Heaters – Pool Pump Timer
Refrigeration	Refrigeration Improvements	– Vending Misers – Refrigerated Case Covers – Economizers – Efficient Refrigeration – Upgrades Motors and Controls – Door Heater Controls – Efficient Compressors and Controls – Door Gaskets and Door Retrofits – Refrigerant Charging Correction – Ice-Makers
Space Cooling	Cooling System Upgrades	– Efficient Chillers – Efficient Cooling Equipment – Ground/Water Source Heat Pump – Chiller Tune-up/Diagnostics – High Efficiency Pumps – Ductless Mini-Splits
Space Heating	Heating System Improvements	– Efficient Heating Equipment – Ground/Water Source Heat Pump – Efficient Heating Pumps, Motors, and Controls – Ductless Mini-Splits
Ventilation	Ventilation Equipment	– Enthalpy Economizer – Variable Speed Drive Controls – Improved Duct Sealing – Destratification Fans – Controlled Ventilation Optimization – Demand Controlled Ventilation
Water Heating	Water Heating Improvements	– Heat Pump Water Heaters – High Efficiency HW Appliances – Low Flow Equipment – Pipe and Tank Insulation – Heat Recovery Systems – Efficient HW Pump and Controls – Solar Water Heating System
Emerging Technologies	Promising New Technologies being considered in Industry	– Active Chilled Beam Heating and Cooling – Ducted Variable-Speed Split System Heat Pump – FANWALL Technology – eCube Refrigeration – Demand Defrost

Technical, Economic, and Achievable Potential

Table 6-17 and Table 6-18 show the cumulative annual technical, economic, maximum achievable (MAP), and realistic achievable (RAP) energy and demand potential in the commercial sector in 2019, 2020, 2021, 2028 and 2036. These values are at the customer meter and do not include any net-to-gross assumptions. Figure 6-7 shows the commercial energy potential as a percent of the commercial sales forecast.

Table 6-17// Summary of Cumulative Annual Commercial Technical, Economic, and Achievable Energy (MWh) Potential

Potential Level	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
Technical	6,974,998	6,980,168	6,985,337	7,021,525	7,062,883
Economic	5,207,938	5,211,045	5,214,152	5,235,902	5,260,759
MAP	263,452	524,285	781,341	2,231,661	2,878,371
RAP	122,045	276,258	461,405	1,531,363	2,039,252

Table 6-18// Summary of Cumulative Annual Commercial Technical, Economic, and Achievable Peak Demand (MW) Potential

Potential Level	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Technical	1,062	1,064	1,065	1,074	1,084
Economic	875	876	877	883	890
MAP	53	102	141	371	486
RAP	22	48	75	230	312

Figure 6-7// Summary of Cumulative Annual Commercial Energy Efficiency Potential as a % of Commercial Forecast Sales

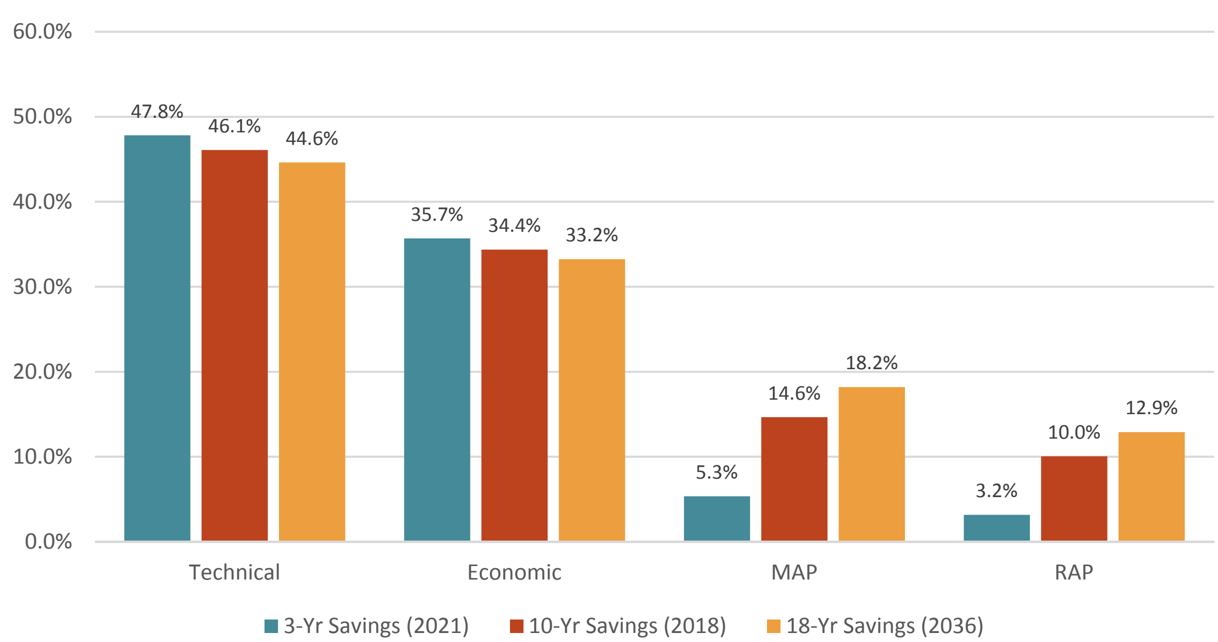


Table 6-19 through Table 6-22 show the commercial technical, economic, maximum and realistic achievable potential by end-use for the years 2019, 2020, 2021, 2028, and 2036. Lighting, cooling, ventilation and refrigeration are among the top savings end uses in each scenario.

Table 6-19// Summary of Cumulative Annual Technical Commercial Energy (MWh) Savings by End-Use

End-Use	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
Lighting	1,750,252	1,751,483	1,752,713	1,761,329	1,771,175
Cooling	1,522,121	1,523,366	1,524,612	1,533,327	1,543,289
Ventilation	997,292	997,775	998,258	1,001,639	1,005,503
Water Heating	38,384	38,415	38,446	38,665	38,915
Refrigeration	1,160,755	1,161,726	1,162,696	1,169,489	1,177,253
Space Heating	160,868	161,015	161,162	162,192	163,369
Office Equipment	779,511	780,029	780,546	784,171	788,313
Miscellaneous	565,816	566,360	566,904	570,714	575,068
Total	**6,974,998**	**6,980,168**	**6,985,337**	**7,021,525**	**7,062,883**

Table 6-20// Summary of Cumulative Annual Economic Commercial Energy (MWh) Savings by End-Use

End-Use	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
Lighting	1,604,443	1,605,609	1,606,775	1,614,936	1,624,264
Cooling	1,223,788	1,224,312	1,224,836	1,228,506	1,232,699
Ventilation	475,133	475,133	475,133	475,133	475,133
Water Heating	36,959	36,987	37,015	37,208	37,430
Refrigeration	893,204	893,798	894,391	898,547	903,295
Space Heating	105,420	105,479	105,538	105,952	106,426
Office Equipment	609,390	609,898	610,405	613,954	618,011
Miscellaneous	304,599	304,828	305,058	306,664	308,500
Total	**5,252,936**	**5,256,043**	**5,259,151**	**5,280,901**	**5,305,758**

Table 6-21// Summary of Cumulative Annual Maximum Achievable Commercial Energy (MWh) Savings by End-Use

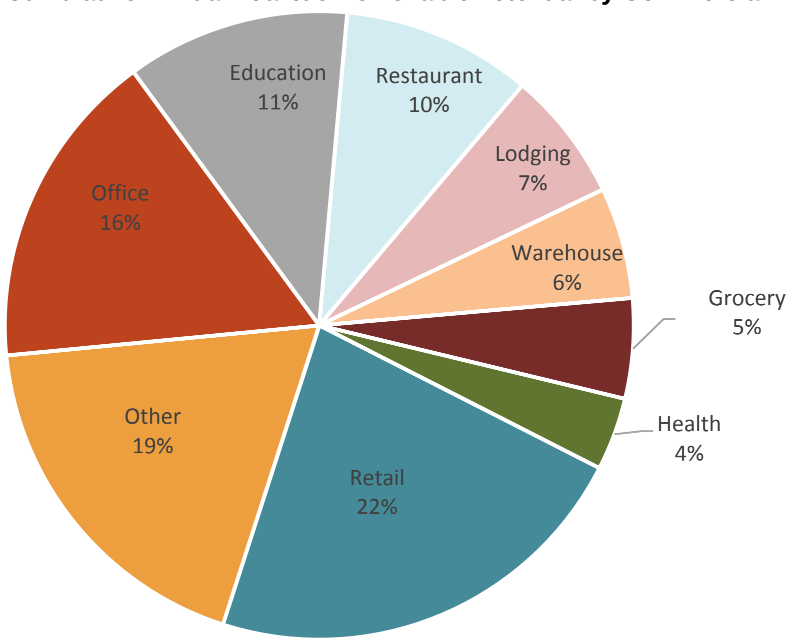
End-Use	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
Lighting	89,410	178,820	268,229	867,399	1,050,170
Cooling	47,434	94,869	142,303	449,416	665,563
Ventilation	18,265	36,531	54,796	182,654	273,981
Water Heating	1,451	2,903	4,354	13,775	19,409
Refrigeration	49,467	98,934	144,624	355,715	435,699
Space Heating	3,916	7,831	11,747	37,198	56,220
Office Equipment	37,261	74,522	111,783	190,392	212,557
Miscellaneous	16,247	29,876	43,504	135,113	164,773
Total	**263,452**	**524,285**	**781,341**	**2,231,661**	**2,878,371**

Table 6-22// Summary of Cumulative Annual Realistic Achievable Commercial Energy (MWh) Savings by End-Use

End-Use	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
Lighting	43,650	99,535	167,656	644,839	824,812
Cooling	15,804	35,874	60,208	227,879	358,602
Ventilation	7,149	16,176	27,081	103,554	163,883
Water Heating	501	1,134	1,898	6,946	9,984
Refrigeration	27,280	62,010	101,919	291,322	370,145
Space Heating	1,201	2,760	4,677	18,314	29,058
Office Equipment	19,161	43,473	72,937	146,359	165,751
Miscellaneous	7,299	15,296	25,028	92,149	117,015
Total	122,045	276,258	461,405	1,531,363	2,039,252

Figure 6-8 provides a breakdown of the commercial RAP savings by several market segments on a cumulative annual basis by 2036. Retail (22%) and office spaces (16%) are the leading two building types in the RAP scenario, with educational buildings and restaurants also exceeding 10% of the total share.

Figure 6-8// 2036 Cumulative Annual Realistic Achievable Potential by Commercial Market Segment



Program MAP and RAP Potential

Table 6-23 and Table 6-24 show the commercial program MAP and RAP potential for each program for the years 2019, 2020, 2021, 2028, and 2036. Program potential is a subset of measure level MAP and RAP to account for measure mapping, NTG impacts, and historical activity.

Table 6-23// Summary of Cumulative Annual Commercial Program MAP Energy (MWh) Savings by Program

End-Use	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
Standard	97,966	227,628	335,911	807,082	800,099
Custom	138,717	246,471	369,231	1,171,528	1,746,195
New Construction	1,872	3,743	5,615	16,904	21,674
RCx	2,781	5,563	8,344	20,487	23,201
Small Business DI	17,828	32,315	49,443	172,718	228,619
Total	**259,164**	**515,720**	**768,543**	**2,188,720**	**2,819,788**

Table 6-24// Summary of Cumulative Annual Commercial Program RAP Energy (MWh) Savings by Program

End-Use	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
Standard	52,082	118,194	198,335	550,814	672,254
Custom	58,898	132,728	220,277	812,425	1,151,254
New Construction	891	2,029	3,414	12,233	16,518
RCx	883	1,996	3,341	9,825	11,155
Small Business DI	7,570	17,402	29,497	119,775	150,727
Total	**120,323**	**272,349**	**454,864**	**1,505,072**	**2,001,909**

Program Cost-Effectiveness

Table 6-25 and Table 6-26 show the MAP and RAP commercial net present values of the total benefits, costs, and savings, along with the TRC ratio for each program.

Table 6-25// Commercial Program MAP NPV Benefits, Costs, Savings, and TRC Ratios by Program ($, in millions)

Program	NPV Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
Standard	$910.0	$500.1	$410	1.8
Custom	$1,405.2	$849.7	$555	1.7
New Construction	$29.0	$16.5	$13	1.8
RCx	$14.1	$5.3	$9	2.7
Small Business DI	$192.2	$148.0	$44	1.3
Total	**$2,550**	**$1,520**	**$1,031**	**1.7**

Table 6-26// Commercial RAP NPV Benefits, Costs, Savings, and TRC Ratios by Program ($, in millions)

Program	NPV Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
Standard	$693.4	$358.2	$335	1.9
Custom	$942.9	$482.0	$461	2.0
New Construction	$20.8	$10.3	$10	2.0
RCx	$6.6	$2.4	$4	2.7
Small Business DI	$132.0	$131.6	$0	1.0
Total	**$1,796**	**$984**	**$811**	**1.8**

6.4.3 Industrial Sector Energy Efficiency Potential

Measures Examined

For the industrial sector, there were 261 total electric savings measures included in the potential energy savings analysis. Table 6-27 provides a brief description of the types of measures included for each end use in the industrial model. The list of measures was developed based on a review of the Ameren Implementation Database, the latest MEMD, and measures found in other TRMs and industrial potential studies. Measure data includes incremental costs, electric energy and demand savings, natural gas savings, and measure life.

Table 6-27// Measures Included in the Electric Industrial Sector Analysis

End Use Type	End Use Description	Measures Included		
Computers & Office Equipment	Equipment Improvements	– Energy Star office equipment including computers, monitors, copiers, multi-function machines. – PC Network Energy Management Controls replacing no central control	– Energy Efficient "Smart" Power Strip for PC/Monitor/Printer – Energy Star UPS	– Energy Star office equipment including computers, monitors, copiers, multi-function machines. – PC Network Energy Management Controls replacing no central control
Water Heating	Water Heating Improvements	– Low Flow Faucet Aerator – Tank Insulation (electric) – Process Cooling Condenser Heat Recovery – HVAC Condenser Heater Recovery Water Heating	– Heat Pump Water Heater – Efficient Hot Water Pump – Hot Water (DHW) Pipe Insulation	– Drain Water Heat Recovery Water Heater – ECM Circulator Pump – Electric Tankless Water Heater
Ventilation	Ventilation Equipment	– Engineered CKV Hood – Variable Speed Drive Control, 15 HP – Variable Speed Drive Control, 5 HP	– Variable Speed Drive Control, 40 HP – Destratification Fan (HVLS) – High Volume Low Speed Fans	– Economizer – High Speed Fans
Space Cooling – Chillers	Cooling System Upgrades	– EMS Pump Scheduling – Wall Insulation – EMS install – Setback with Electric Heat – Web Enabled EMS – Efficient Chilled Water Pump – Chilled Hot Water Reset – EMS Optimization – Water Side Economizer – Chiller Tune Up	– Water-Cooled Screw Chiller > 300 ton – Water-Cooled Centrifugal Chiller > 300 ton – Integrated Building Design – Retro-commissioning – Motor Belt Replacement – VAV System Conversion – Air-Cooled Recip Chiller – Air-Cooled Screw Chiller – High Efficiency Pumps – Ceiling Insulation	– HVAC Occupancy Sensors – Programmable Thermostats – Economizer – Energy Efficient Windows – Roof Insulation – Zoning – Improved Duct Sealing – Window Improvements – Cool Roofing
Space Cooling – Unitary and Split AC	Cooling System Upgrades	– EMS Pump Scheduling – Wall Insulation – EMS install – Setback with Electric Heat – Web Enabled EMS – EMS Optimization – Integrated Building Design – Retro-commissioning – Room AC	– Ground Source Heat Pump - Cooling – Water Loop Heat Pump (WLHP) - Cooling – Ceiling Insulation – DX Condenser Coil Cleaning – HVAC Occupancy Sensors – Economizer – Programmable Thermostats – Air Source Heat Pump - Cooling – Energy Efficient Windows	– Packaged Terminal Air Conditioner (PTAC) - Cooling – AC 240K - 760 K – Roof Insulation – Zoning – Improved Duct Sealing – Window Improvements – Ductless (mini split) - Cooling – Cool Roofing

End Use Type	End Use Description	Measures Included		
Lighting	Lighting Improvements	– Lighting Power Density - Parking Garage – CFL Screw-in – Lighting Power Density- Exterior – Lighting Power Density - Interior – CFL Screw in Specialty – LED Downlight – CFL Reflector Flood – LED Exit Sign – LED Screw In Replacing Incandescent – LED Specialty replacing incandescent – Stairwell Bi-Level Control – HID Fixture Upgrade - Pulse Start Metal Halide – CFL Fixture – Interior Induction Lighting – Long Day Lighting Dairy	– High Intensity Fluorescent Fixture (replacing HID) – LED Grow Light – Daylight Sensor Controls – Central Lighting Control – Occupancy Sensor & Daylight Sensor – Lamp & Ballast Retrofit (Low Wattage HPT8 Replacing T12) – Occupancy Sensor – LED Tube Lighting – Lamp & Ballast Retrofit (HPT8 Replacing T12) – LED High Bay Lighting – Lamp & Ballast Retrofit (Low Wattage HPT8 Replacing Standard T8) – Switching Controls for Multilevel Lighting (Non-HID) – Exterior Linear Fluorescent – Exterior HID Replaced with CFL	– Garage Bi-level Controls – LED Specialty replacing CFL – Garage HID replacement with LED – Illuminated Signs to LED – Interior Non-Highbay/Lowbay LED Fixtures – LED Low Bay Lighting – Exterior Bi-level Controls – T5 HP replacing T12 – Lamp & Ballast Retrofit (HPT8 Replacing Standard T8) – LED Screw In Replacing CFL – Light Tube – 42W 8 lamp Hi Bay CFL – Exterior HID replaced with LED – LED Troffer
Space Heating	Heating System Improvements	– EMS Pump Scheduling – Wall Insulation – EMS install – Setback with Electric Heat – Web Enabled EMS – EMS Optimization – VFD Pump – Integrated Building Design – Retro-commissioning	– Ground Source Heat Pump - Heating – Ceiling Insulation – Water Loop Heat Pump (WLHP) - Heating – Destratification Fan (HVLS) – HVAC Occupancy Sensors – Programmable Thermostats – Economizer – ECM motors on furnaces	– Air Source Heat Pump - Heating – Energy Efficient Windows – Roof Insulation – Zoning – Improved Duct Sealing – Window Improvements – Ductless (mini split) - Heating – Cool Roofing
Other		– Engine Block Heater Timer – Parking Garage Exhaust Fan CO Control – High Efficiency Transformer, three-phase	– NEMA Premium Transformer, three-phase – High Efficiency Transformer, single-phase	– NEMA Premium Transformer, single-phase – Optimized Snow and Ice Melt Controls
Machine Drive	Machine Drive Improvements	– Advanced Lubricants – Compressed Air System Management – Compressed Air - Advanced Compressor Controls	– Automatic Drains, High efficiency nozzles and other (comp air) – VFD for Process Pumps – Pump System Efficiency Improvements	– Industrial Motor Management – Fan System Improvements – High Efficiency Pumps – Advanced Efficient Motors

End Use Type	End Use Description	Measures Included		
		– Elec motors replacing pneumatic (comp air) – Compressed Air Audits and Leak Repair – Storage Tank Addition (comp air) – VFD for Process Fans	– Motor System Optimization (Including ASD) – Electric Supply System Improvements – Sensors & Controls	– High Efficiency Dryers (comp air) – Energy Information System
Process Cooling & Refrigeration	Process Cooling and Refrigeration Improvements	– Improved Refrigeration – Electric Supply System Improvements	– Sensors & Controls	– Energy Information System
Process Heating	Heating Improvements	– Electric Supply System Improvements	– Sensors & Controls	– Energy Information System
Industrial Other		– Barrel Insulation - Inj. Molding (plastics) – High Efficiency Welders	– Pellet Dryer Insulation (plastics) – 3 Phase High Eff Battery Charger	– Injection Molding Machine - efficient (plastics) – Fiber Laser Replacing CO2 laser (auto industry)
Agriculture		– Fan Thermostat Controller – VFD for Process Fans - Agriculture – Milk Pre-Cooler Heat Exchanger – VFD for Process Pumps - Agriculture – Low Pressure Sprinkler Nozzles	– VFD for Process Pumps - Irrigation – Variable Speed Drives for Dairy Vacuum Pumps – Other Industrial -Low-Energy Livestock Waterer – Other Industrial -Dairy Refrigerator Tune-Up	– Grain Storage Temperature and Moisture Management Controller – Greenhouse Environmental Controls – Variable Speed Drive with Heat Exchanger, Milk – Scroll Compressor with Heat Exchanger for Dairy Refrigeration

Technical, Economic, and Achievable Potential

Table 6-28 and Table 6-29 show the cumulative annual technical, economic, maximum achievable (MAP), and realistic achievable (RAP) energy and demand potential in the industrial sector in 2019, 2020, 2021, 2028 and 2036. These values are at the customer meter and do not include any net-to-gross assumptions. Figure 6-9 shows the industrial energy potential as a percent of the industrial sales forecast.

Table 6-28// Summary of Cumulative Annual Industrial Technical, Economic, and Achievable Energy (MWh) Potential

Potential Level	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
Technical	1,105,539	1,105,539	1,105,539	1,105,539	1,105,539
Economic	970,995	970,995	970,995	970,995	970,995
MAP	57,434	95,868	133,469	369,133	527,202
RAP	26,475	50,992	80,201	252,182	378,896

Table 6-29// Summary of Cumulative Annual Industrial Technical, Economic, and Achievable Peak Demand (MW) Potential

Potential Level	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Technical	305	305	305	305	305
Economic	277	277	277	277	277
MAP	15	26	36	104	149
RAP	6	13	21	69	105

Figure 6-9// Summary of Cumulative Annual Industrial Energy Potential as a % of Industrial Forecast Sales

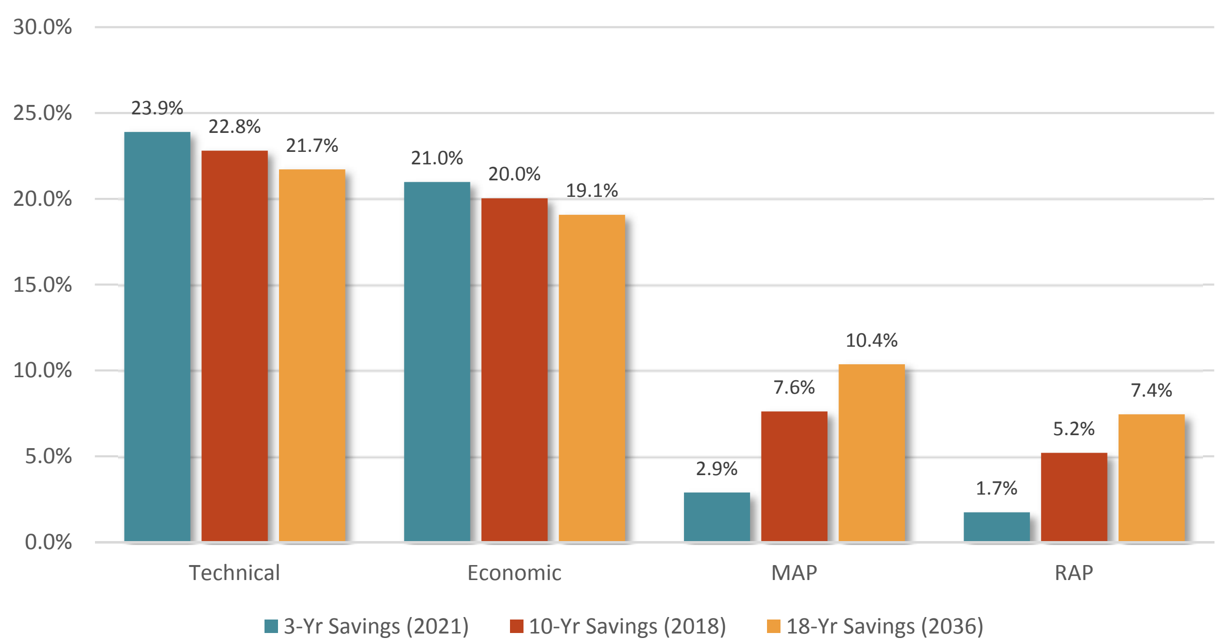


Table 6-30 through Table 6-33 show the industrial technical, economic, maximum and realistic achievable potential by end-use for the years 2019, 2020, 2021, 2028, and 2036. Machine drives is the leading end use in each scenario.

Table 6-30// Summary of Cumulative Annual Technical Industrial Energy (MWh) Savings by End-Use

End-Use	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
Machine Drive	511,578	511,578	511,578	511,578	511,578
Lighting	176,710	176,710	176,710	176,710	176,710
Space Cooling	194,247	194,247	194,247	194,247	194,247
Ventilation	48,578	48,578	48,578	48,578	48,578
Process Heating and Cooling	88,086	88,086	88,086	88,086	88,086
Space Heating	48,987	48,987	48,987	48,987	48,987
Other	1,303	1,303	1,303	1,303	1,303
Agriculture	23,972	23,972	23,972	23,972	23,972
Water Heating	4,117	4,117	4,117	4,117	4,117
Computers & Office Equipment	7,961	7,961	7,961	7,961	7,961
Total	**1,105,539**	**1,105,539**	**1,105,539**	**1,105,539**	**1,105,539**

Table 6-31// Summary of Cumulative Annual Economic Industrial Energy (MWh) Savings by End-Use

End-Use	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
Machine Drive	511,578	511,578	511,578	511,578	511,578
Lighting	153,893	153,893	153,893	153,893	153,893
Space Cooling	130,542	130,542	130,542	130,542	130,542
Ventilation	24,581	24,581	24,581	24,581	24,581
Process Heating and Cooling	83,781	83,781	83,781	83,781	83,781
Space Heating	33,100	33,100	33,100	33,100	33,100
Other	673	673	673	673	673
Agriculture	21,965	21,965	21,965	21,965	21,965
Water Heating	4,117	4,117	4,117	4,117	4,117
Computers & Office Equipment	6,767	6,767	6,767	6,767	6,767
Total	**970,995**	**970,995**	**970,995**	**970,995**	**970,995**

Table 6-32// Summary of Cumulative Annual Maximum Achievable Industrial Energy Savings by End-Use

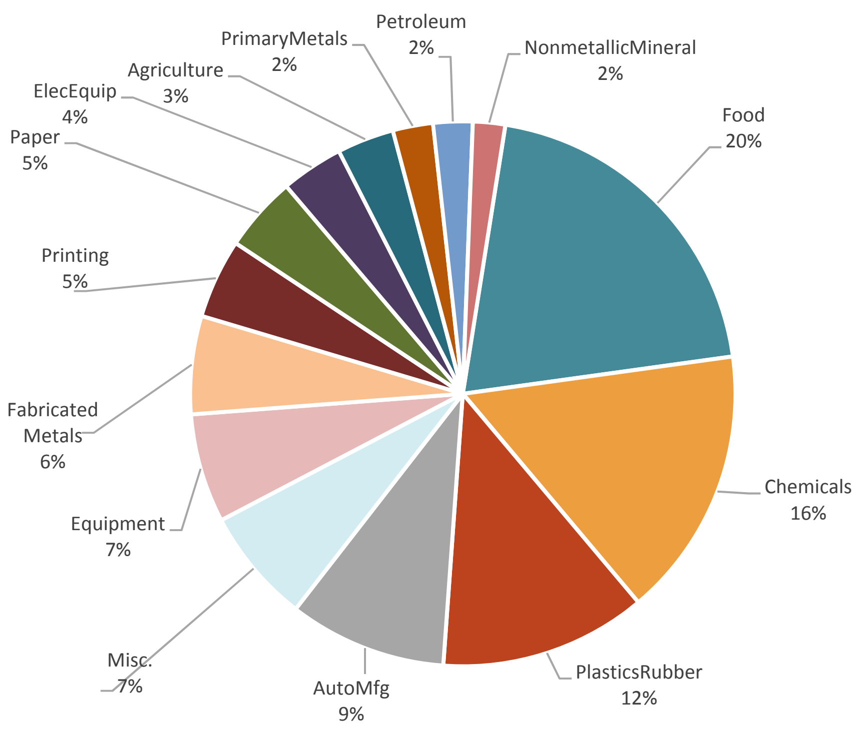
End-Use	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
Machine Drive	38,934	58,867	78,801	195,334	277,231
Lighting	7,630	15,261	22,891	75,558	98,915
Space Cooling	3,898	7,797	11,695	38,538	64,460
Ventilation	1,032	2,065	3,097	10,324	15,486
Process Heating and Cooling	3,329	6,658	9,154	26,625	38,358
Space Heating	1,011	2,021	3,032	10,066	16,446
Other	27	55	82	223	322
Agriculture	849	1,697	2,546	8,485	11,605
Water Heating	173	346	519	1,730	2,088
Computers & Office Equipment	550	1,101	1,651	2,250	2,291
Total	**57,434**	**95,868**	**133,469**	**369,133**	**527,202**

Table 6-33 // Summary of Cumulative Annual Realistic Achievable Industrial Energy (MWh) Savings by End-Use

End-Use	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
Machine Drive	19,885	35,510	53,974	148,377	221,587
Lighting	2,878	6,741	11,584	48,375	67,411
Space Cooling	797	2,005	3,624	16,754	29,683
Ventilation	472	1,080	1,823	7,223	11,658
Process Heating and Cooling	1,687	3,868	6,096	20,352	31,188
Space Heating	181	456	824	4,021	7,246
Other	5	12	21	81	130
Agriculture	235	558	968	4,438	7,196
Water Heating	51	117	198	769	980
Computers & Office Equipment	284	647	1,090	1,791	1,815
Total	**26,475**	**50,992**	**80,201**	**252,182**	**378,896**

Figure 6-10 provides a breakdown of the industrial RAP savings by several market segments on a cumulative annual basis by 2036. More than half of the RAP savings are attributable to the food (20%), chemicals (16%), plastics/rubber (12%) and auto manufacturing (9%) market segments.

Figure 6-10 // 2036 Cumulative Annual Realistic Achievable Potential by Industrial Market Segment



Program MAP and RAP Potential

Table 6-34 and Table 6-35 show the Cumulative Annual industrial program MAP and RAP potential for each program for the years 2019, 2020, 2021, 2028, and 2036. Program potential is a subset of measure level MAP and RAP to account for measure mapping, NTG impacts, and historical activity.

Table 6-34// Summary of Cumulative Annual Industrial Program MAP Energy (MWh) Savings by Program

Program	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
Custom	52,476	85,951	118,635	323,890	472,719
Standard	4,316	8,631	12,947	39,150	44,900
Total	**56,791**	**94,583**	**131,582**	**363,040**	**517,620**

Table 6-35// Summary of Cumulative Annual Industrial Program RAP Energy (MWh) Savings by Program

Program	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
Custom	24,462	46,304	72,202	222,590	340,689
Standard	1,781	4,146	7,093	25,898	31,904
Total	**26,243**	**50,450**	**79,295**	**248,488**	**372,593**

Program Cost-Effectiveness

Table 6-36 and Table 6-37 show the MAP and RAP industrial net present values of the total benefits, costs, and savings, along with the TRC ratio for each program.

Table 6-36// Industrial Program MAP NPV Benefits, Costs, Savings, and TRC Ratios by Program ($, in millions)

Program	NPV Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
Custom	$591.3	$116.7	$474.6	5.1
Standard	$48.5	$23.9	$24.7	2.0
Total	**$640**	**$141**	**$499**	**4.6**

Table 6-37// Industrial RAP NPV Benefits, Costs, Savings, and TRC Ratios by Program ($, in millions)

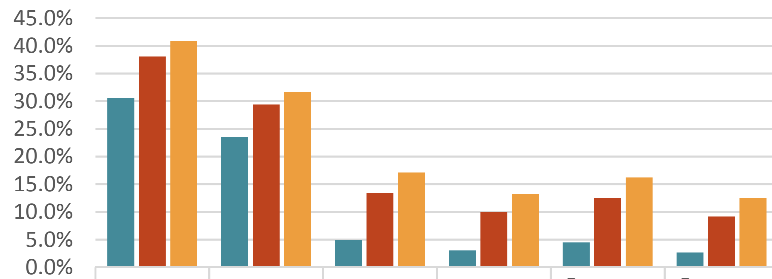
Program	NPV Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
Custom	$405.4	$63.3	$342.1	6.4
Standard	$31.6	$13.9	$17.6	2.3
Total	**$437**	**$77**	**$360**	**5.7**

6.4.4 Total Energy Efficiency Potential for All Sectors[43]

Figure 6-11, Table 6-38 and Table 6-39 show the results for technical, economic, achievable, and program energy efficiency potentials for all sectors combined. The cost-effective economic potential ranges from 23.5% to 31.7% across the 3-year and 18-year timeframes. The program RAP is 2.7% (~850,000 MWh and 150 MW) in the first three years of the study, growing to 12.5% across the 18-year timeframe. These percentages are calculated as the cumulative annual savings relative to the forecast for the given year of the timeframe.

[43] 4 CSR 240-22.050(5)(D); 4 CSR 240-22.050(5)(E)

Figure 6-11// Summary of Cumulative Annual Energy Efficiency MWh Savings Potential (as a % of Forecast MWh Sales) for All Customer Sectors Combined



	Technical	Economic	MAP	RAP	Program MAP	Program RAP
3-Yr Savings (2021)	30.6%	23.5%	5.0%	3.0%	4.5%	2.7%
10-Yr Savings (2018)	38.1%	29.4%	13.4%	10.0%	12.5%	9.2%
18-Yr Savings (2036)	40.8%	31.7%	17.1%	13.3%	16.2%	12.5%

3-Yr Savings (2021) 10-Yr Savings (2018) 18-Yr Savings (2036)

Table 6-38// Summary of Cumulative Annual Technical, Economic, Achievable, and Program MWh Savings Potentials for All Customer Sectors Combined

Potential Level	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
Technical	8,730,820	9,370,599	9,768,144	12,723,396	14,347,026
Economic	6,703,667	7,219,857	7,499,412	9,828,748	11,133,329
MAP	592,947	1,160,987	1,580,917	4,491,981	6,015,579
RAP	249,603	610,452	971,348	3,347,068	4,669,994
Program MAP	536,931	1,050,014	1,430,637	4,173,376	5,697,800
Program RAP	219,337	534,733	849,945	3,063,628	4,405,575

Table 6-39// Summary Cumulative Annual Technical, Economic, Achievable, and Program MW Savings Potentials for All Customer Sectors Combined

Potential Level	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Technical	1,497	1,623	1,724	2,247	2,480
Economic	1,252	1,349	1,423	1,830	2,008
MAP	117	226	311	815	1,085
RAP	49	116	185	583	799
Program MAP	100	193	263	724	982
Program RAP	41	96	150	499	711

Table 6-40 shows the total cost- effectiveness results for all cost-effective programs program MAP and program RAP scenarios. These summaries are based on the 18-year timeframe of the study.

Table 6-40// Summary of Cost-Effectiveness ($, in millions)

	NPV Lifetime Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
Program MAP	$5,483	$2,887	$2,595	1.90

	NPV Lifetime Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
Program RAP	$4,128	$2,027	$2,101	2.04

6.4.5 Cost of Acquiring EE Program Potential

Table 6-41 and Table 6-42 show the Program MAP and RAP program costs. Non-equipment incentives are included in these budgets.

Table 6-41// Summary of Program MAP Budget Requirements ($, in millions)

	Residential Achievable Potential Cost	Commercial Achievable Potential Cost	Industrial Achievable Potential Cost	Total Achievable Potential Cost
2019	$118.3	$120.8	$12.1	$251.2
2020	$115.6	$120.8	$12.1	$248.5
2021	$107.4	$120.8	$12.1	$240.3
2022	$106.2	$120.8	$12.1	$239.1
2023	$104.9	$120.8	$12.1	$237.9
2024	$104.8	$120.8	$12.1	$237.7
2025	$104.2	$120.8	$12.1	$237.1
2026	$103.1	$120.8	$12.1	$236.0
2027	$102.1	$120.8	$12.1	$235.0
2028	$94.1	$120.8	$12.1	$227.0
2029	$96.6	$120.8	$12.1	$229.6
2030	$96.4	$120.8	$12.1	$229.3
2031	$98.0	$120.8	$12.1	$230.9
2032	$105.3	$120.8	$12.1	$238.3
2033	$103.6	$120.8	$12.1	$236.5
2034	$107.7	$120.8	$12.1	$240.6
2035	$107.7	$120.8	$12.1	$240.6
2036	$107.5	$120.8	$12.1	$240.4

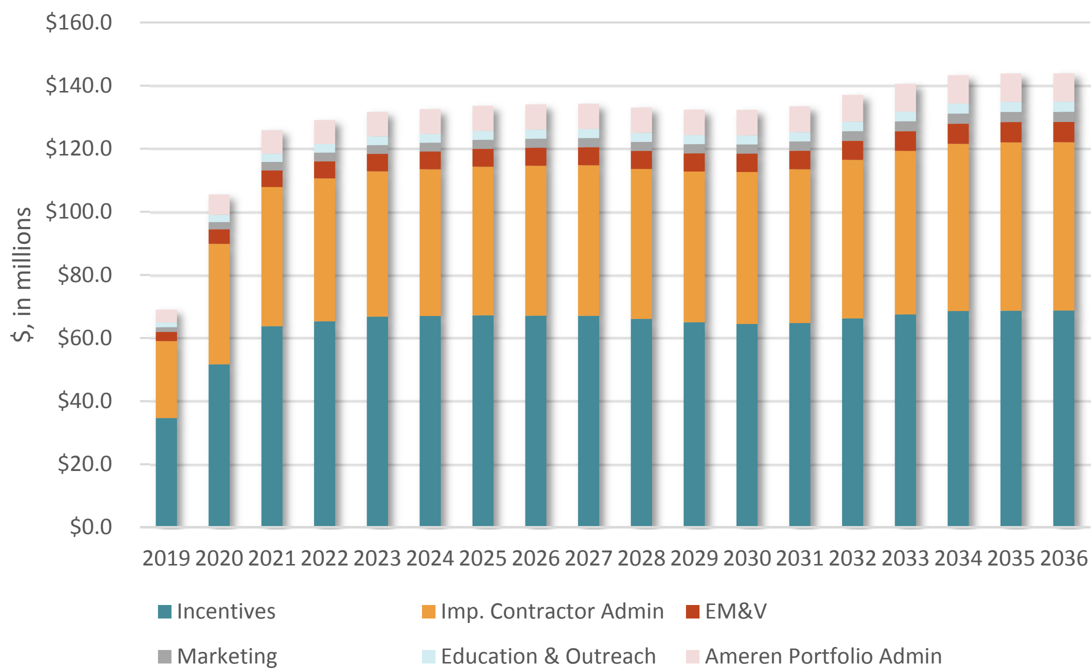
Table 6-42// Summary of Program RAP Budget Requirements ($, in millions)

	Residential Achievable Potential Cost	Commercial Achievable Potential Cost	Industrial Achievable Potential Cost	Total Achievable Potential Cost
2019	$31.5	$35.2	$2.2	$69.0
2020	$56.8	$45.5	$3.1	$105.5
2021	$66.0	$55.9	$4.0	$125.9
2022	$66.5	$58.3	$4.4	$129.1
2023	$66.6	$60.4	$4.6	$131.7
2024	$66.8	$61.0	$4.8	$132.5
2025	$67.1	$61.5	$4.9	$133.6
2026	$67.0	$62.1	$4.9	$134.0
2027	$66.7	$62.7	$5.0	$134.3
2028	$65.1	$62.9	$5.0	$133.0
2029	$64.5	$62.9	$5.0	$132.4
2030	$64.4	$62.9	$5.0	$132.3
2031	$65.5	$62.9	$5.0	$133.4
2032	$69.1	$62.9	$5.0	$137.0
2033	$72.6	$62.9	$5.0	$140.5
2034	$75.4	$62.9	$5.0	$143.3

	Residential Achievable Potential Cost	Commercial Achievable Potential Cost	Industrial Achievable Potential Cost	Total Achievable Potential Cost
2035	$75.9	$62.9	$5.0	$143.8
2036	$76.0	$62.9	$5.0	$143.9

Figure 6-12 provides the program RAP budgets in graphical form with breakouts of the budget line items of incentives, implementation contractor administrative costs, EM&V, marketing, education and outreach, and Ameren portfolio administrative costs. The overall costs rise from $67 million to $122 million in the first three years of the study, and then level off before rising to $139 million by 2036.

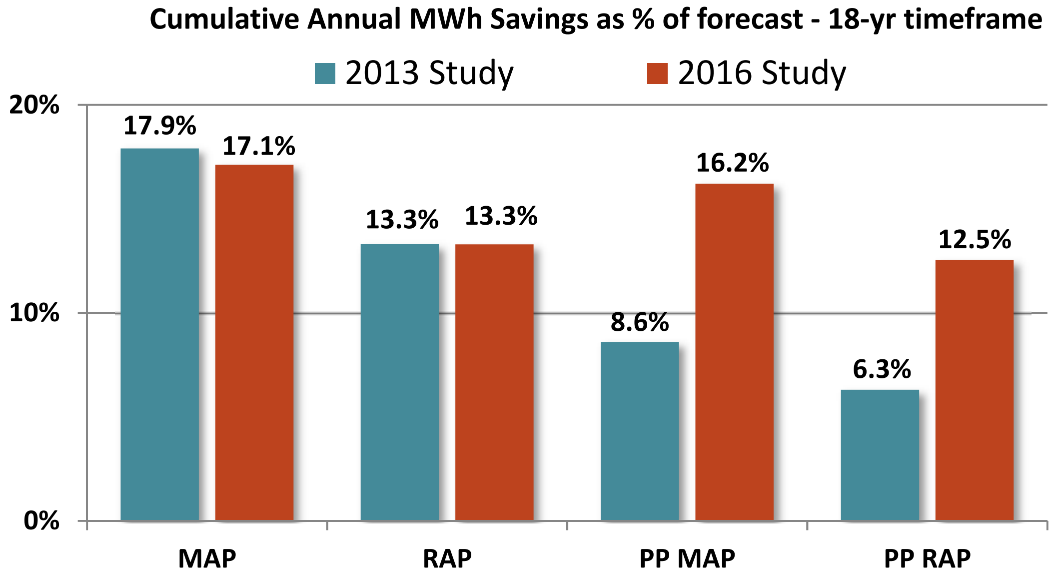
Figure 6-12// Total Program RAP by Budget Category



6.5 COMPARISON TO PRIOR STUDY IN 2013 AND OTHER STUDIES

Figure 6-13 provides a graphical comparison of the results of this study to the previous study performed by Enernoc in 2013. The MAP and RAP are very similar across the 18-year timeframe in both studies. The program MAP and program RAP however are significantly greater in the 2016 study.

Figure 6-13// Comparison between 2016 study to 2013 study



Other Recent Potential Studies

Table 6-43 below compares the results of the new Ameren Missouri energy efficiency potential study to results of other publicly available energy efficiency potential studies conducted throughout the United States. It is useful to examine this comparison to see if the results for the Ameren Missouri service area are similar to other recent potential studies. Results of additional energy efficiency potential studies can be located at the following U.S. Department of Energy, Energy Efficiency Potential Studies Catalog web site: http://www.energy.gov/eere/slsc/energy-efficiency-potential-studies-catalog. This U.S. DOE web site reports that "States, utilities, and non-governmental organizations across the country have commissioned analyses over the years to identify potential energy savings (typically for electricity) available within their jurisdictions. These studies can be used to fulfill a variety of needs, including energy efficiency program planning, state goal setting, utility resource planning, and other priorities."

As one can see from the data in the Table below, the achievable energy efficiency potential for the Ameren Missouri service area is similar to the potential estimates in several other recent studies.

Table 6-43 // Results of Recent, Publicly Available Energy Efficiency Potential Studies in the US

State	Study Year	Author	Study Period	# of Years	Cumulative Annual Achievable Savings Potential (Percent of MWh Sales Forecast)
Ameren Missouri	2016	GDS Associates/EMI Consulting	2019-2036	18	17.1%
Ameren Illinois	2016	Applied Energy Group Inc.	2017-2036	18	16.4%
ComEd	2013	ICF International	2013-2018	6	10.0%
KCP&L	2013	Navigant	2014-2033	20	17.1%-21.2%
Ohio (AEP)-Base Case	2014	American Electric Power	2015-2034	20	24.0%
Pennsylvania	2015	GDS Associates, Inc.	2016-2025	10	13.2%
USA	2014	Electric Power Research Institute	2015-2035	21	14.0%

A 2015 report by the American Council for an Energy Efficient Economy (ACEEE) offers information regarding the current savings and spending related to energy efficiency by state.[44] Based on self-reported data, twelve states annually **spent more than 2%** of electric sales revenue on electric energy efficiency programs in 2014. GDS also examined actual energy efficiency savings data for 2010 and 2011 from the US Energy Information Administration (EIA) on the top twenty energy efficiency electric utilities. These top twenty utilities saved over 2% of annual kWh sales in 2010 with their energy efficiency programs, and 3.8% of annual kWh sales in 2011. These percentage savings are attributable to energy efficiency measures installed in a one-year time frame and demonstrate what can be accomplished with full-scale and aggressive implementation of programs.

[44] American Council for an Energy Efficient Economy, "The 2015 State Energy Efficiency Scorecard", Report #U1509, October 2015.

7 BEHAVIORAL PROGRAMS POTENTIAL

7.1 INTRODUCTION

GDS conducted an analysis of the technical, economic, maximum achievable, and realistic achievable, potential for behavior programs and measures. This chapter of the report provides an overview of the type of behavioral potential analyzed in the study, provides a brief overview of behavioral program efforts in the Ameren Missouri territory to date, and summarizes the results of our analysis.

7.2 OVERVIEW OF BEHAVIORAL MEASURE TYPES

Behavioral measures are typically defined as feedback programs, namely those that use usage information to prompt customers to take action. Feedback programs can be grouped into two general categories: indirect or asynchronous programs, and direct or real-time energy data programs. These two types or programs summarized below.

Indirect Feedback Programs

Indirect feedback programs are those that provide feedback to customers after energy consumption has occurred. This information is often provided with monthly energy bills, and may use framing, peer comparisons, or social norming behavioral tactics. The most common of these is the OPower Home Energy Report.

Direct Feedback Programs

Real-time energy data programs provide real-time feedback on information such as energy pricing and energy consumption. This information may be provided to customers via in-home meter displays, online portals, or mobile applications.

Indirect feedback programs have gained traction throughout the U.S in recent years. For instance, Opower currently claims to serve more than 60 million utility customers through its suite of products, including its home energy reports. These types of energy efficiency measures and programs have become an increasingly important component of utility DSM portfolios. The evaluation industry has proven that these programs have reliable and verifiable savings ranging between 1% to 3% annually. Evaluation techniques have become much more sophisticated for these types of programs in order to detect with accuracy these relatively low levels of savings. The Opower website currently provides more than 50 links to past evaluation reports for utilities throughout the U.S. which demonstrate the energy and demand savings achieved by these types of programs[45].

7.3 LOCAL CONTEXT - BEHAVIORAL MEASURES IN AMEREN MISSOURI

Ameren Missouri developed a new behavioral DSM program as part of its suite of MEEIA Cycle 2 programs. The Ameren Missouri Home Energy Report program provides participating customers throughout the Ameren Missouri service territory with personalized information about their energy use to help them save energy and money. The report compares a customer's home energy use to similar homes in the area, along with personalized recommendations on ways to cut energy costs. The settlement agreement plans include an estimated 225,000 participating customers per year. The current Ameren TRM estimates the savings for these measures at 1.5% of baseline consumption and a one-year useful life. These are good planning assumptions that will need to be trued-up once a full year of program savings and participation have accrued.

[45] https://opower.com/resource_type/mv-reports/

7.4 MEASURES ANALYZED

The study analyzed measures in the residential and commercial sectors. For the residential sector, there were two principle measures: home energy reports and home energy monitors. Home energy monitors did not pass the cost-effectiveness screening for the residential sector. In some cases, home energy reports do pass the cost-effectiveness screening. For the commercial sector, there were three principle measures: commercial building energy reports, whole-building energy monitoring, and in-building energy use displays.

The residential analysis parsed out savings estimates according to consumption categories (high, medium, and low) in order to recognize differences in corresponding savings estimates. The savings estimates by consumption category are based on the PY5 Ameren Illinois behavior program evaluation report[46]. The cost estimates are based on information provided by Ameren Missouri.

Table 7-1// List of Key Behavioral Measures and Assumptions

Measure	Savings Estimate	Cost	Cost-Effectiveness Findings
Home Energy Report – single-family (low usage)	0.75%	$7.85 per year	Not cost-effective*
Home Energy Report – single-family (medium usage)	1.17%	$7.85 per year	Cost-effective
Home Energy Report – single-family (high usage)	2.17%	$7.85 per year	Cost-effective
Behavior Based Efficiency (Commercial Energy Reports)	3.0%	$8.88 per year	Cost-effective
Whole-Building Energy Monitoring	9.0%	$1 per SqFt	Not Cost-effective
In-Building Energy Use Displays	10.0%	$250 upfront cost	Cost-effective

*Low usage customers were included in the program potential because the overall program would be cost effective even with these customers.

GDS attempted to recognize projected participation rates in MEEIA Cycle 2 when developing projections of participation levels in the early years of the study. Table 7-2 below shows the number of participants in the residential and commercial behavioral programs during the first three years of the study (2019-2021). The residential program RAP participation is based on adoption rates beginning at 45% of eligible customers and increasing to 60% during the first three years and ultimately to 95% after seven years. The residential program MAP participation rate starts at 95%. The commercial participation assumes some time to initiate the program and gain traction, and therefore starts with a lower adoption rate than the residential sector. The commercial program participation assumes that all SGS and LGS customer, approximately 71% of 2015 energy usage and 90% of all commercial customers, will receive a commercial building report in less than 5 years. As seen below, during the first three years, almost 90,000 customers (57% of total commercial customers) will receive billing reports out of 155,000 total commercial customers.

Table 7-2// Estimated Customers Participating in Behavior Programs (2019-2021)

Sector	2019	2020	2021
Residential	238,044	238,044	317,392
Commercial	23,890	29,501	35,621

[46] Impact and Process Evaluation of Ameren Illinois Company's Behavioral Modification Program (PY5). Opinion Dynamic's. 2014.

7.5 RESULTS

This section provides a summary of the savings estimates, in terms of energy and demand savings. There is also a presentation of the behavior program cost-effectiveness and program budgets.

Savings

Figure 7-1, Table 7-3 and Table 7-4 show the results for technical, economic, achievable, and program potentials for behavioral measures. The cost-effective economic potential is 1.1% in 2021 and 1.0% by 2036. The program RAP is 0.5% (~135,000 MWh and 150 MW) in the first three years of the study, and holding steady at 0.5% across the 18-year timeframe. These percentages are calculated as the cumulative annual savings relative to the forecast for the given year of the timeframe.

Figure 7-1// Summary of Cumulative Annual Behavioral Energy Savings Potential (as a % of Forecast Sales) for All Customer Sectors Combined

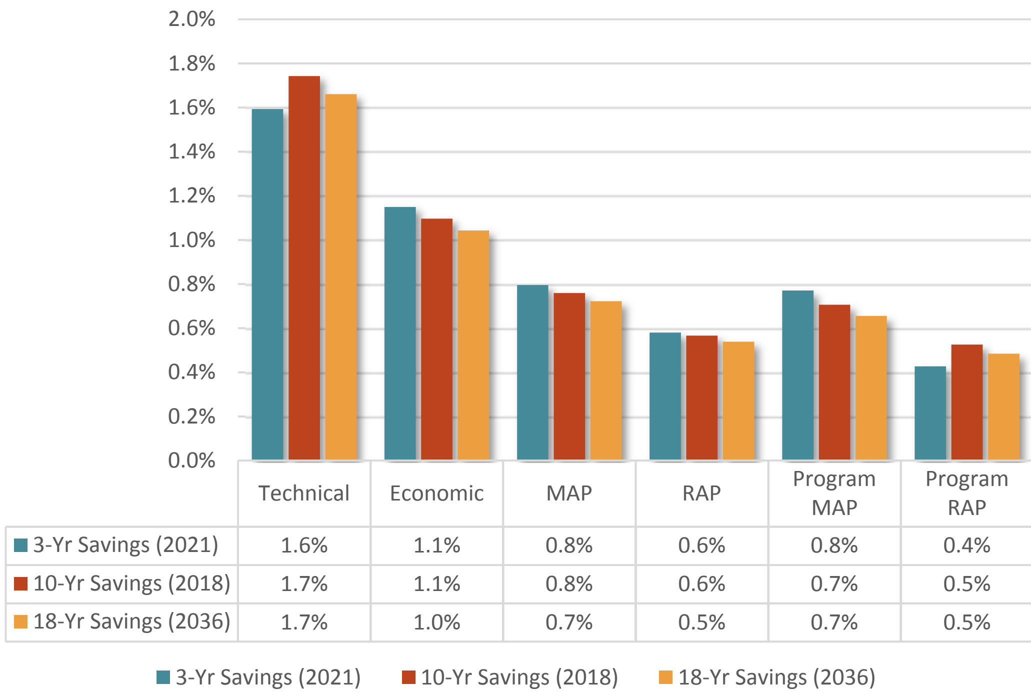


Table 7-3// Cumulative Annual Energy Savings Technical, Economic, Achievable, and Program Potentials for Behavioral Measures

Potential Level	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
Technical	434,564	471,419	508,251	582,543	583,580
Economic	366,479	366,479	366,479	366,479	366,479
MAP	204,553	253,672	253,672	253,672	253,672
RAP	150,460	173,672	184,908	189,155	189,155
Program MAP	200,693	246,651	245,751	235,897	230,398
Program RAP	84,433	106,521	136,093	175,645	170,122

Table 7-4// Cumulative Annual Demand Savings Technical, Economic, Achievable, and Program Potentials for Behavioral Measures

Potential Level	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Technical	47	52	56	64	64
Economic	40	40	40	40	40
MAP	23	29	29	29	29
RAP	17	20	21	22	22
Program MAP	23	29	29	28	28
Program RAP	10	13	16	21	21

Cost-Effectiveness

Table 7-5 shows the total cost- effectiveness results for all cost-effective programs program MAP and program RAP scenarios. These summaries are based on the 18-year timeframe of the study.

Table 7-5// Summary of Cost-Effectiveness of Behavior Program Measures ($, in millions)

	NPV Lifetime Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
Program MAP	$229.4	$68.1	$161.3	3.4
Program RAP	$160.4	$54.0	$106.4	3.0

Program Costs

Table 7-6 and Table 7-7 show the Program MAP and RAP program costs. Non-equipment incentives are included in these budgets.

Table 7-6// Summary of Program MAP Budget Requirements ($, in millions) for Behavioral Measures

	Residential Achievable Potential Cost	Commercial Achievable Potential Cost	Total Achievable Potential Cost
2019	$4.5	$1.4	$5.9
2020	$4.5	$1.4	$5.9
2021	$4.5	$1.4	$5.9
2022	$4.5	$1.4	$5.9
2023	$4.5	$1.4	$5.9
2024	$4.5	$1.4	$5.9
2025	$4.5	$1.4	$5.9
2026	$4.5	$1.4	$5.9
2027	$4.5	$1.4	$5.9
2028	$4.5	$1.4	$5.9
2029	$4.5	$1.4	$5.9
2030	$4.5	$1.4	$5.9
2031	$4.5	$1.4	$5.9
2032	$4.5	$1.4	$5.9
2033	$4.5	$1.4	$5.9
2034	$4.5	$1.4	$5.9
2035	$4.5	$1.4	$5.9
2036	$4.5	$1.4	$5.9

Table 7-7// Summary of Program RAP Budget Requirements ($, in millions) for Behavioral Measures

	Residential Achievable Potential Cost	Commercial Achievable Potential Cost	Total Achievable Potential Cost
2019	$2.1	$0.5	$2.7
2020	$2.1	$0.7	$2.8
2021	$2.8	$0.8	$3.6
2022	$2.8	$0.8	$3.6
2023	$4.0	$0.8	$4.8
2024	$4.0	$0.8	$4.8
2025	$4.5	$0.8	$5.3
2026	$4.5	$0.8	$5.3
2027	$4.5	$0.8	$5.3
2028	$4.5	$0.8	$5.3
2029	$4.5	$0.8	$5.3
2030	$4.5	$0.8	$5.3
2031	$4.5	$0.8	$5.3
2032	$4.5	$0.8	$5.3
2033	$4.5	$0.8	$5.3
2034	$4.5	$0.8	$5.3
2035	$4.5	$0.8	$5.3
2036	$4.5	$0.8	$5.3

8 DEMAND RESPONSE POTENTIAL

8.1 INTRODUCTION

This DR potential study provides a roadmap for both policy makers and Ameren Missouri as they develop additional strategies and programs for reducing the peak summer electric demand in the Ameren Missouri service area. The report identifies a comprehensive set of DR program options and presents an analysis of the cost, benefits, and potential summer peak demand reductions associated with each DR program option. GDS used a systematic, bottom-up approach (at the customer segment and end use level) to develop estimates of DR potential for both the residential and non-residential (commercial and industrial) sectors. This study provides annual estimates of DR potential for the period 2019-2036.

The key objectives of this study include:

- Conduct an 18-year bottom-up DR potential study to determine the technical, economic, MAP and RAP of a comprehensive portfolio of DR program options to reduce summer peak demand for electricity in the Ameren Missouri service area.[47]
- Identify the costs, benefits, and cost-effectiveness of all DR programs included in the study.[48]
- Identify the total and incremental annual DR program budget that would be required to acquire all Program MAP and Program RAP DR potential.[49]
  - **Program MAP** represents an estimate of the maximum cost-effective DR potential that can be achieved over the 18-year study period. For this study, this is defined as offering default opt-out DR rate options for all customers and achieving customer participation rates (take rates) for non-rate DR program options that reflect a "best practices" estimate of what could eventually be achieved. Default opt-out rates, where customers are enrolled by default but have the option to switch to another rate, are assumed for MAP because they can garner participation three to five times higher than opt-in enrollment.[50]
  - **Program RAP** represents an estimate of the amount of DR potential that can be realistically achieved over the 18-year study period. For this study, this is defined as offering opt-in DR rate options for all customers and achieving customer take rates for non-rate DR program options that reflect a realistic estimate of what could eventually be achieved assuming typical or "average" industry experience.

This potential study evaluated DR potential for two achievable potential scenarios:

1) **Base Case Scenario:** The Base Case scenario assumes that all cost-effective DR programs will be implemented by Ameren and load control switches will be used to control central air conditioning. No utility spending caps are placed on the achievable potential for this scenario.
2) **Smart Thermostat Scenario:** The smart thermostat scenario also assumes that all cost-effective DR programs will be implemented, but in this scenario controllable smart thermostats (such as Nest or Ecobee) will be used to control air conditioning equipment. As in the Base Case, no spending caps are placed on the achievable potential for this scenario.

47 Rules of Department of Economic Development, 4 CSR 240-22.050 (2)
48 Rules of Department of Economic Development, 4 CSR 240-22.050 (5)
49 Rules of Department of Economic Development, 4 CSR 240-22.050 (3)(G)5.E.
50 A Review of Alternative Rate Designs: Industry Experience with Time-Based Rates and Demand Charge Rates for Mass-Market Customers, Rocky Mountain Institute, May 2016.

Ameren Missouri will use the results of this study in its integrated resource planning process to analyze various levels of peak demand reductions attributable to DR initiatives at various levels of cost. By conducting this study, Ameren Missouri has adhered to both the Missouri Public Service Commission ("Commission") rules, 4 CSR 240-3.164 regarding potential study requirements for purposes of complying with the Missouri Energy Efficiency Investment Act (MEEIA) and 4 CSR 240-22 regarding potential study requirements for Ameren Missouri's next Integrated Resource Plan (IRP). [51]

8.1.1 Definition of Demand Response

According to the Federal Energy Regulatory Commission (FERC), demand response is defined as changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized. FERC's definition of demand response conforms to the North American Electric Reliability Corporation (NERC) definition developed by a consortium of utilities and end users – of which Ameren Missouri had a leadership role.

The Midwest Independent System Operator (MISO) defines demand response as the ability of a Market Participant to reduce its electric consumption in response to an instruction received from MISO. Market Participants can provide such demand response either with discretely interruptible or continuously controllable loads or with behind-the-meter generation. In short, resources have to be dispatchable and measurable. Demand response rate options such as TOU or CPP don't meet these requirements. However, these rates can provide value for Ameren Missouri if they lower their peak demand requirements. That reduction in peak load can translate into lower capacity requirements. Utilities in MISO have to demonstrate that they have sufficient capacity on a forward basis.

This study uses the broader FERC definition of demand response so that all potential DR, including rate options, are identified. Ameren Missouri's integrated resource planning team will analyze and adjust as necessary the identified DR potential for what can be counted in the MISO market and/or how DR potential will be used to construct alternative resource plans.

The definition of DR used in this study is also consistent with the Missouri Integrated Resource Planning (IRP) rules which consider demand response to include both energy management measures and demand-side rates, and the Missouri Energy Investment Act which includes load management, demand response, and interruptible or curtailable load as acceptable "demand-side programs".

The **Missouri IRP** rules define demand response options as follows:

Energy-Management Measure *means any device, technology, or operating procedure that makes it possible to alter the time pattern of electricity usage so as to require less generating capacity or to allow the electric power to be supplied from more fuel-efficient generating units. Energy-management measures are sometimes referred to as demand response.*[52]

[51] The Missouri Rules of the Department of Economic Development (4 CSR 240-22) require that electric utilities in Missouri prepare an integrated resource plan (IRP) that "[consider[s] and analyze[s] demand-side efficiency and energy management measures on an equivalent basis with supply-side alternatives in the resource planning process." per Section 4 CSR 240-22.010(2)(A). Section 4 CSR 240-22.050 prescribes the elements of the demand-side analysis, including reporting requirements. A copy of the Missouri rules governing electric utility resource planning is available on the Missouri Secretary of State's website. Details of MEEIA are available on the Missouri Public Service Commission website.

[52] Rules of Department of Economic Development, 4 CSR 240-22.020 (21)

Demand-Side Rate *means a rate structure for retail electric service designed to reduce the net consumption or modify the time of consumption of a customer rate class.*[53]

The **Missouri Energy Investment Act** (MEEIA) states:

Demand Response refers to measures that decrease peak demand or shift demand to off-peak periods.[54]

A **Demand-Side Program** is any program conducted by the utility to modify the net consumption of electricity on the retail customer's side of the electric meter, including, but not limited to energy efficiency measures, load management, demand response, and interruptible or curtailable load.[55]

8.1.2 Demand Response at Ameren Missouri

Ameren Missouri has offered eight demand response programs. They are described below:

1) Ameren Missouri offered an interruptible rate to large industrial customers through 2000. Five customers providing a total contractual commitment of 54 MW participated on the rate. The interruptible tariff was structured with a 50% demand charge credit that averaged approximately $5/kW-month at the time. Interruptible events were limited to system reliability emergencies. Few interruptible events were called each year. The interruptible rate tariff was discontinued in 2000.

2) Ameren Missouri offered a subsequent pilot interruptible rate referred to as Rider G for smaller industrial customers with smaller demand charge credits. Four customers providing a total contractual commitment of 17 MW participated on the rate. As their production demands increased, the four participating customers eventually opted out of the rate. Rider G was discontinued in 2003.

3) Ameren Missouri offered commercial and industrial customers a voluntary curtailment rate option or a peak power rebate (PPR) program referred to as Rider L beginning in 1999. Ameren Missouri opted to offer a non-penalty based price-responsive DR on the premise that customers may be more likely to sign-up for non-penalty based programs and that penalty based and non-penalty based programs have similar response characteristics. The PPR program structure keeps customers on the standard rate for all non-event hours but offers an incentive rate for a pre-determined number (in this case 60) of critical-peak event hours during a program year.

   Twenty customers representing a total potential load of 67 MW enrolled in Rider L. The last Rider L curtailment event was called in 2009. A total of four Rider L customers participated in the 2009 curtailment events and these customers combined offered a range of approximately 6 to 9 MW of peak demand reduction per event.

4) Ameren Missouri also offered a commercial and industrial customer interruptible program with a slight difference from the Rider L program logic. Rider M was also voluntary and paid participating customers a monthly curtailment option fee plus a price per kWh. The fees and kWh prices provided under Rider M were agreed upon in advance by the Company and the customer, based upon various customer selected curtailment options and were applicable during the summer billing months of June – September.

53 Rules of Department of Economic Development, 4 CSR 240-22.020 (12)
54 Missouri Energy Efficiency Investment Act, RSMo, Section 393.1075
55 Missouri Energy Efficiency Investment Act, RSMo, Section 393.1075

5) In Case No ER-2007-0002, Ameren Missouri proposed a tariff to implement a new industrial demand response pilot program known as Rider IDR. The pilot program was designed to assess whether industrial process customers would respond to load curtailments to interrupt their use of power when they are directed to do so by Ameren Missouri. The tariff defined the occasions when a customer could be asked to interrupt, but the decision to interrupt would be at the discretion of Ameren Missouri. Rider IDR limited the hours available for interruption to 200 hours per year. The customer could choose the amount of curtailable load to be included in the program. The availability of the program was to be limited to no more than five customers with a total demand response aggregated load of 100 MW and would last for three years. Customers who agreed to participate in the program would be paid a demand credit of $2.00 per kW per month with an additional credit of $0.08 per kWh when interrupted.

Rider IDR was never implemented due primarily to the inability to align the provisions in the tariff with the MISO Business Practice manual to bid demand response resources into the MISO market.

6) In 2004 and 2005, Ameren Missouri conducted a Residential Time-Of-Use (RTOU) Pilot study. The RTOU Pilot study encompassed two innovative rate offerings that provided financial incentives for customers to modify their consumption patterns during higher priced critical peak periods (CPP). Originally, the rate offerings were organized into three treatment groups for the Pilot study:

- The first group of customers received a three-tier TOU rate[56] with high differentials.
- The second group of customers received the same TOU rate as the first treatment group but was also subject to a critical peak pricing (CPP) element.
- The third group of customers received the same treatment, i.e., TOU rate and CPP, as treatment group number two but had enabling technology, i.e., a "smart" programmable controllable thermostat, installed by Ameren. The enabling technology automatically increased the customer's thermostat setting during critical peak pricing events.

For 2005, the first treatment group, i.e., the time-of-use rate only, was dropped from the Pilot Study. The principal reason for dropping the time-of-use only group was that this group failed to display a significant shift in load from the on-peak to the mid-peak or off-peak periods. Therefore, the second year pilot focused on the critical peak pricing element and those customers with smart thermostats.

Three Tier TOU with CPP (CPP)

CPP Event	Hour Ending		Control Group (kW)	RTOU Pilot Group (kW)	Difference Control-RTOU (kW)	Percent Difference (%)	T-Test	Pr>|t|	Ho: Control=RTOU
Date	Start	End							
30-Jun-05	3:00 PM	6:59 PM	5.35	4.85	0.50	9.3%	2.63	0.0088	Reject
21-Jul-05	3:00 PM	6:59 PM	5.71	4.91	0.80	14.1%	3.75	0.0002	Reject
22-Jul-05	3:00 PM	6:59 PM	5.84	5.05	0.79	13.5%	3.54	0.0005	Reject
26-Jul-05	3:00 PM	6:59 PM	5.98	4.91	1.06	17.8%	5.28	0.0000	Reject
2-Aug-05	3:00 PM	6:59 PM	5.38	4.73	0.65	12.1%	3.24	0.0013	Reject
9-Aug-05	3:00 PM	6:59 PM	5.64	4.74	0.90	16.0%	4.33	0.0000	Reject
10-Aug-05	3:00 PM	6:59 PM	5.01	4.24	0.76	15.2%	4.00	0.0000	Reject
19-Aug-05	3:00 PM	6:59 PM	5.61	4.88	0.74	13.1%	3.54	0.0004	Reject
Average			5.56	4.84	0.72	13.0%	3.90	0.0001	Reject

Three Tier TOU with CPP and Thermostat (CPP-THERM)

CPP Event	Hour Ending		Control Group (kW)	RTOU Group (kW)	Difference Control-RTOU (kW)	Percent Difference (%)	T-Test	Pr>|t|	Ho: Control=RTOU
Date	Start	End							
30-Jun-05	3:00 PM	6:59 PM	5.02	4.30	0.72	14.4%	2.93	0.0036	Reject
21-Jul-05	3:00 PM	6:59 PM	5.37	4.09	1.27	23.7%	5.22	0.0001	Reject
22-Jul-05	3:00 PM	6:59 PM	5.38	4.18	1.20	22.4%	5.39	0.0001	Reject
26-Jul-05	3:00 PM	6:59 PM	5.56	4.38	1.18	21.2%	4.93	0.0001	Reject
2-Aug-05	3:00 PM	6:59 PM	5.23	3.66	1.57	30.0%	6.30	0.0001	Reject
9-Aug-05	3:00 PM	6:59 PM	5.47	4.01	1.46	26.7%	5.76	0.0001	Reject
10-Aug-05	3:00 PM	6:59 PM	4.95	3.82	1.13	22.8%	4.95	0.0001	Reject
19-Aug-05	3:00 PM	6:59 PM	5.38	3.97	1.41	26.1%	5.49	0.0001	Reject
Average			5.29	4.05	1.24	23.5%	6.05	0.0001	Reject

56 The TOU rates differ by season (i.e., summer versus winter).

Fifteen-minute interval load monitoring equipment was installed on the total premises load and provided for a statistically representative sample of customers in each treatment group. In addition to the treatment groups, Ameren Missouri constructed control groups for use in the analysis. Once again, fifteen-minute interval load monitoring equipment was installed on a statistically representative sample of the homes of control group customers.

The table above presents findings for the eight CPP periods in 2005. The table presents the average demand for the control and RTOU treatment groups. The group with the enabling DR technology saved an additional .52 kW per home on average as compared to the group without the enabling technology.

7) From 1993 to 1998, Ameren Missouri implemented a residential central air conditioner direct load control program called "No Sweat." The Company invested a total of $1.9 million implementing the program during that time. The program logic was to pay customers an annual incentive payment of $40 for the option to interrupt their air conditioners a finite number of times. Customers participating in the program also received free HVAC diagnostic services from HVAC contractors hired by Ameren Missouri. Communication to switches that cycled customer air conditioners off and on was handled by the existing 154 MHz radio infrastructure at Ameren Missouri. Dead zones and poor reception reduced the cycling benefits, while the manual policing of the radio system added to the program cost.

8) In 2009, Ameren Missouri conducted a Personal Energy Manager (PEM) Rebate Pilot Program that had the dual purposes of assessing the effectiveness of potential residential price response programs and testing the associated technology. Part of the technology test was to determine whether new vendor (Tendril) hardware was compatible with Ameren Missouri's automated meter reading (AMR) system and how well it interfaced with the AMR meters.

This pilot program provided bill credits to residential customers who, at Ameren Missouri's request, voluntarily reduced their electricity consumption during *Price Response Events* designated by Ameren Missouri. To minimize any potential customer inconveniences, participants were recruited from Ameren Missouri staff who volunteered to take part. The program provided technology that enabled interactive energy monitoring and remote thermostat control in the home, allowing Ameren Missouri to test this technology. (The technology also assisted the customer in managing their electricity consumption during non-events.)

The Pilot program was implemented with installation of varying configurations of the new Tendril equipment in the homes of 374 Ameren Missouri employees during June and July of 2009. The industry name for demand response programs with voluntary participation and no penalties for non-participation when load curtailment events are called is Peak Time Rebates (PTR). A key finding from the 2009 Ameren Missouri PEM pilot in the independent third-party evaluation of the program conducted by the team of Cadmus and PA Consulting was the difficulty in estimating an accurate baseline against which to assess load reductions by program participants. Cadmus and PA noted that customers who had taken no load reduction actions were often given an incentive payment and customers who had taken load reduction actions were often not compensated for their efforts. This may have been the first documentation that questioned the premise that PTR programs had no "losers." Subsequent evaluation, measurement and verification of large scale PTR programs in other jurisdictions, most notably California, have shown that PTR is not a low-cost program when payment for non-performance due to measurement error is considered.

Each of the eight Ameren Missouri demand response programs had a finite effective useful life.

Some programs were terminated because the value received was not commensurate with the value paid. Some programs were terminated because they were pilot programs and fulfilled their pilot program testing objectives. Some programs were terminated because they were evaluated to not be cost-effective. Some programs were terminated simply because not enough customers were interested in participating.

8.2 CHARACTERIZATION OF PEAK DEMAND CONSUMPTION IN THE AMEREN MISSOURI SERVICE AREA

8.2.1 Customer Segmentation

The first step in this DR potential study was to segment the market into customer segments that are relevant for analyzing DR potential, given the available data. The first level of segmentation was by customer class: Residential, Commercial, and Industrial. Within the residential class, customers were further segmented by the saturation of end uses that are typically targeted in DR programs such as central air conditioning (CAC) and electric water heating. For Commercial and Industrial customers, additional segmentation is based on rate schedule and the saturation of targeted end uses such as HVAC systems and electric water heating.

Table 8-1 presents the forecasted number of customers by segment in 2018, the coincident summer demand for each customer segment and the average coincident demand per customer[57]. Coincident customer demand refers to the customer load at the time of the system summer peak.

Table 8-1// Forecasted 2018 Customers and Coincident Peak Demand by Rate Schedule

Customer Segment	Number of Customers	Coincident Segment Summer Peak (MW)	Per Customer Coincident Summer Peak (kW)
Residential	1,051,435	3,793.5	3.61
Commercial Small General Service	146,743	884.2	6.03
Commercial Large General Service	9,777	1,507.7	154.2
Commercial Small Primary Service	481	460.3	956.9
Commercial Large Primary Service	38	307.8	8,099.1
Industrial Small General Service	2,965	31.2	10.5
Industrial Large General Service	971	191.5	197.2
Industrial Small Primary Service	188	215.9	1,148.6
Industrial Large Primary Service	35	326.3	9,323.7
Total	**1,212,633**	**7,718.4**	**6.4**

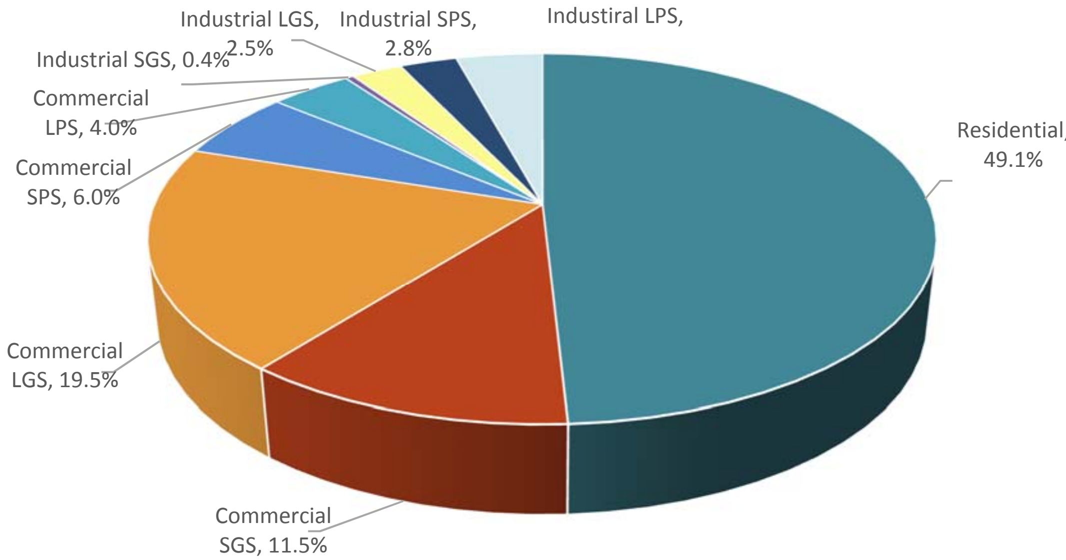
The end use saturations used to further characterize the market for potential DR programs were taken from the 2013 Ameren Missouri Residential Appliance Saturation Survey and Commercial Baseline Study.

Figure 8-1 shows the contribution that each identified customer segment is forecasted to make to the

[57] Provided by Ameren Missouri in June 2016

Ameren Missouri system peak in 2018. Of the segments identified in this study, residential customers have the largest contribution with 49.1% of the Company's summer peak load.

Figure 8-1// Contribution to Ameren Missouri's Summer Peak Demand by Customer Segment



8.2.2 Customer Forecast

GDS forecasted the number of customers in each segment for the period 2019 through 2036[58]. This forecast was used to estimate the number of eligible customers for each DR program option that was included in the analysis.

Table 8-2// Ameren Missouri Customer Forecast by Segment

	2019	2020	2021	2028	2036
Residential	1,054,300	1,056,359	1,058,193	1,067,732	1,077,405
Commercial SGS	147,665	148,633	149,608	152,902	153,567
Commercial LGS	9,848	9,928	10,014	10,312	10,369
Commercial SPS	488	489	490	495	496
Commercial LPS	38	39	39	40	40
Industrial SGS	2,942	2,919	2,899	2,839	2,829
Industrial LGS	969	967	966	962	961
Industrial SPS	188	188	188	188	188
Industrial LPS	35	35	35	34	34

8.3 METHODOLOGY[59]

8.3.1 Demand Response Program Options[60]

This study included analysis of a comprehensive set of DR program options that fall into three main categories: Direct Load Control, Rate Options, and Aggregator Programs. Table 8-3 provides a brief

[58] Can be found in Section 5 of this report.

[59] 4 CSR 240-22.050(5)(G); 4 CSR 240-22.050(2)

[60] 4 CSR 240-22.050(1)(A); 4 CSR 240-22.050(3)(C);

description of these DR program options and identifies the eligible customer segment for each DR program that was considered in this study.

Table 8-3 // Demand Response Program Options and Eligible Markets[61]

Demand Response – Measure Applicability			Rate Schedule			
Demand Response Option	Description	Residential	Small General Service (SGS) <101 kW	Large General Service (LGS) 101 - 500 kW	Small Primary Service (SPS) 501 - 5000 kW	Large Primary Service (LPS) >5000 kW
Direct Load Control						
1. Control of Central Air Conditioners with Load Control Switch	The compressor of the air conditioner is remotely shut off (cycled) by the system operator for periods that may range from 7 ½ to 15 minutes during every 30-minute period (i.e., 25%-50% duty cycle).	X	X			
2. Control of Electric Water Heaters	The water heater is remotely shut off by the system operator for time periods normally ranging from 2 to 8 hours. Some utilities (such as Central Electric Power Cooperative in South Carolina) report that they may shut off the water heater for periods longer than 8 hours.	X	X			
3. Control of Room Air Conditioners	The compressor of the air conditioner is remotely shut off (cycled) by the system operator for periods that may range from 7 ½ to 15 minutes during every 30-minute period (i.e., 25%-50% duty cycle).	X	X			
4. Electric Thermal Storage – Cooling	The use of a cold storage medium such as ice, chilled water, or other liquids. Off-peak energy is used to produce chilled water or ice for use in cooling during peak hours. The cool storage process is limited to off-peak periods.		X	X	X	
5. Control of Swimming Pool Pumps	The swimming pool pump is remotely shut off by the system operator for periods normally ranging from 2 to 4 hours.	X	X			
6. Control of Commercial Lighting - On/Off, Dimming	The lighting load is remotely shut off by the system operator for periods normally ranging from 2 to 4 hours.		X			

[61] 4 CSR 240-22.050(1)(D)

Demand Response – Measure Applicability			Rate Schedule			
			Small General Service (SGS)	Large General Service (LGS)	Small Primary Service (SPS)	Large Primary Service (LPS)
Demand Response Option	Description	Residential	<101 kW	101 - 500 kW	501 - 5000 kW	>5000 kW
7. Agricultural Irrigation Pump Control	The irrigation pump is remotely shut off by the system operator for periods normally ranging from 2 to 4 hours.		X	X		
8. Control of Air Conditioners with Controllable "Smart" Thermostats (i.e. Nest, Ecobee)	The system operator can remotely raise the AC's thermostat set point during peak load conditions, lowering AC and/or heating load. Consideration of utility control should address customer control capabilities including the Nest Learning Thermostat as well as services provided by ISPs, home security cos.	X	X			
9. Control of Smart Appliances	Direct utility control of smart appliances.	X				
Rate Options						
10. Base Interruptible Program	A discounted rate is offered to the customer for agreeing to interrupt or curtail load during peak period. The interruption is mandatory. No buy-through options are available.			X	X	(1)
11. Time of Use Rate w/o Enabling Technology	A retail rate with different prices for usage during different blocks of time. Daily pricing blocks could include on-peak, mid-peak, and off-peak periods. Pricing is pre-defined, and once established do not vary with actual cost conditions.	X	X			(1)
12. Time of Use Rate with Enabling Technology	A retail rate with different prices for usage during different blocks of time. Daily pricing blocks could include on-peak, mid-peak, and off-peak periods. Pricing is pre-defined, and once established do not vary with actual cost conditions. Includes enabling technology that connects technologies within building. Only customers with AC	X	X			(1)

Demand Response – Measure Applicability		Rate Schedule				
			Small General Service (SGS)	Large General Service (LGS)	Small Primary Service (SPS)	Large Primary Service (LPS)
Demand Response Option	Description	Residential	<101 kW	101 - 500 kW	501 - 5000 kW	>5000 kW
13. Time of Use Rate with Enabling Technology for Smart Appliances	A retail rate with different prices for usage during different blocks of time. Daily pricing blocks could include on-peak, mid-peak, and off-peak periods. Pricing is pre-defined, and once established do not vary with actual cost conditions. Includes enabling technology that connects Smart Appliances within building. Only customers with AC.	X				
14. Critical Peak Pricing Rate w/o Enabling Technology	A retail rate in which an extra-high price for electricity is provided during a limited number of critical periods (e.g. 100 hours) of the year. Market-based prices are typically provided on a day-ahead basis, or an hour-ahead basis.	X	X	X	X	(1)
15. Critical Peak Pricing Rate with Enabling Technology	A retail rate in which an extra-high price for electricity is provided during a limited number of critical periods (e.g. 100 hours) of the year. Market-based prices are typically provided on a day-ahead basis, or an hour-ahead basis. Includes enabling technology that connects technologies within building. Only for customers with AC.		X	X	X	(1)
16. Critical Peak Pricing Rate with Enabling Technology for Smart Appliances	A retail rate in which an extra-high price for electricity is provided during a limited number of critical periods (e.g. 100 hours) of the year. Market-based prices are typically provided on a day-ahead basis, or an hour-ahead basis. Includes enabling technology that connects Smart Appliances within building. Only customers with AC.	X				
17. Charging of Golf Carts Off Peak	Special rate service for golf courses that charge electric golf carts off-peak.		X			
18. Charging of Plug-In Utility Vehicles-Off Peak	Special rate service for businesses that charge electric utility vehicles off-peak.		X	X	X	

Demand Response – Measure Applicability			Rate Schedule			
			Small General Service (SGS)	Large General Service (LGS)	Small Primary Service (SPS)	Large Primary Service (LPS)
Demand Response Option	Description	Residential	<101 kW	101 - 500 kW	501 - 5000 kW	>5000 kW
19. Electric Vehicle Charging Station Off Peak (Personal and Fleet)	Special rate service for electric vehicles that charge off-peak.	X	X	X	X	X
20. Inclining Block Rates	Rate program where the per-unit price of electricity increases with the level of consumption.	X				
Aggregator Programs						
21. Capacity Bidding Programs (CBP)	CBP is a flexible bidding program offering qualified businesses payments for agreeing to reduce load (for example, lighting, HVAC, escalators/elevators, pumps or some manufacturing equipment) when a CBP event is called. Make monthly nominations and receive capacity payments based on the amount of capacity reduction nominated each month, plus energy payments based on your actual kilowatt-hour (kWh) energy reduction when an event is called. The amount of capacity nomination can be adjusted on a monthly basis. The program can be Internet-based, providing ready access to program information and ease-of-use. Penalties occur if load nominations are not met.			X	X	X
22. Demand Bidding Programs (DBP)	DBP is a year-round, flexible, Internet-based bidding program that offers business customers credits for voluntarily reducing power when a DBP event is called.		X			

(1) Because the very largest customers are often unique cases with more constraints on their rate design due to special contracts, they do not often participate in dynamic pricing programs.

8.3.2 Demand Response Potential Assessment Approach

The analysis for this study was conducted using the GDS DR Model. The GDS DR model is an Excel spreadsheet tool that allows the user to determine the achievable potential for a demand response program based on the following two basic equations that can be chosen be the model user.

Technical Potential | All technically feasible demand reductions are incorporated to provide a measure of the theoretical maximum DR savings potential. This assumes 100% of eligible customers will participate in all programs regardless of cost-effectiveness.

Economic Potential | Only cost-effective DR program options are included in the economic potential. In accordance with guidance provided by Ameren Missouri, DR program capital costs, such as the cost of load control switches, are not amortized over the assumed useful life of the equipment.

If the model user chooses to base the estimated potential demand reduction on a percent of the total per participant coincident peak (CP) load, then:

$$\text{Achievable DR Potential} = \text{Per Customer CP Load for Eligible Customer Segment} \times \text{Potentially Eligible Customers} \times \text{Eligible Customer Participation Rate} \times \text{Percent CP Load Reduction Per Participant}$$

If the model user chooses to base the estimated potential demand reduction on a per customer CP load reduction value, then:

$$\text{Achievable DR Potential} = \text{Potentially Eligible Customers} \times \text{Eligible Customer Participation Rate} \times \text{CP Load Reduction Per Participant}$$

Achievable Potential is the cost-effective DR potential that can practically be attained in a real-world program delivery scenario, assuming that a certain level of market penetration can be attained. Achievable potential takes into account real-world barriers to convincing customers to participate in cost-effective DR programs. Achievable savings potential savings is a subset of economic potential.

The framework for assessing the cost-effectiveness of DR programs is based *on A Framework for Evaluating the Cost-Effectiveness of Demand Response, Prepared for the National Forum on the National Action Plan on Demand Response*.[62]

The TRC Test is used to determine the cost-effectiveness of each demand response program. Benefits are based on avoided generation capacity, energy (including load shifting) and T&D infrastructure costs. Costs include incremental program equipment costs (such as control switches or smart thermostats), fixed program capital costs (such as the cost of a central controller), program administrative, marketing and evaluation costs. Incremental equipment program costs are included for both new and replacement units (such as control switches) to account for units that are replaced at the end of their useful life.[63]

Two main achievable potential scenarios were evaluated for demand response:

MAP represents an estimate of the maximum cost-effective DR potential that can be achieved over the

[62] Study was prepared by Synapse Energy Economics and the Regulatory Assistance Project, February 2013.
[63] 4 CSR 240-22.050(5)(B)

18-year study period. For this study, this is defined as offering default opt-out DR rate options for all customers and achieving customer participation rates (take rates) for non-rate DR program options that reflect a "best practices" estimate of what could eventually be achieved. Default opt-out rates, where customers are enrolled by default but have the option to switch to another rate, are assumed for MAP because they can garner participation three to five times higher than opt-in enrollment.

RAP represents an estimate of the amount of DR potential that can be realistically achieved over the 18-year study period. For this study, this is defined as offering opt-in DR rate options for all customers and achieving customer take rates for non-rate DR program options that reflect a realistic estimate of what could eventually be achieved assuming typical or "average" industry experience.

In addition to the MAP and RAP DR potential GDS also developed estimates of program DR potential.

Program Potential includes the impact of energy efficiency gains realized in the Energy Efficiency Potential study. These gains include the changes that occur when old equipment is replaced with high efficiency equipment. This also accounts for the changes to federal efficiency standards that begin in 2020. Yearly impacts were developed for space cooling (used for DLC of AC programs) and whole building (used for rate programs that affect multiple measures). Table 8-4 shows the energy efficiency savings impacts reflected in the final year of the study (2036). The space cooling efficiency gains were used for the direct load control of air conditioning programs, and the general sector efficiency gains were used for all other programs included in Program RAP potential.

Table 8-4// Energy Efficiency Savings Impacts in 2036

	MAP	RAP
Residential	12.3%	10.5%
Residential - Space Cooling	19.0%	16.1%
Commercial	16.2%	10.4%
Commercial - Space Cooling	29.8%	19.1%
Industrial	18.8%	13.1%

8.3.3 Avoided Costs and Other Economic Assumptions

The avoided costs used to determine utility benefits were provided by Ameren Missouri. Avoided electric generation capacity refers to the DR program benefit resulting from a reduction in the need for new peaking generation capacity. Demand response can also produce energy related benefits. If the demand response option is considered "load shifting", such as direct load control of electric water heating, the consumption of energy is shifted from the control period to the period immediately following the period of control. For this study, GDS assumed that the energy is shifted with no loss of energy. For power suppliers, this shift in the timing of energy use can produce benefits from either the production of energy from lower cost resources or the purchase of energy at a lower rate. If the program is not considered to be "load shifting", such as lighting control, the measure is turned off during peak control hours, and the energy is saved altogether. DR programs can also potentially delay the construction of new transmission and distribution lines and facilities, which is reflected in avoided T&D costs.

The discount rate used in this study is 5.8%. A peak demand line loss factor of 5.72% for residential and 4.84% for commercial and industrial sectors, and a reserve margin of 17 % (for firm load reduction such as direct load control) were also applied to demand reductions at the customer meter. All of these values were provided by Ameren Missouri.

The number of annual control hours for all direct load control (DLC) programs was assumed to be 80[64]. The critical peak pricing rate assumes 60 annual hours[65]. For purposes of this study, the inclining block rate is in effect 80 hours a year[66]. For PEV off-peak charging, the total number of annual hours when load is shifted from on-peak to off-peak hours is assumed to be 1,497[67]. TOU programs impact participant use over the entire year, not just a small number of control. For a standard TOU rate the annual load shifting hours are assumed to be 1,300.[68] The total annual amount of load shifted from on-peak to off-peak hours is based on Ameren residential load data for the summer peak period, average peak summer weekday and average peak non-summer weekday.

The number of control units per participant was assumed to be 1 for all direct load control programs using switches, because load control switches can control up to two units. However, for controllable thermostats, some participants have more than one thermostat. The average number of residential thermostats per home was assumed to be 1.1[69]. The number of non-residential thermostats per customer is scaled up to 1.7 to reflect the difference in per customer coincident peak demand in the small general service class relative to per customer coincident peak demand in the residential sector. This approach was taken because there was no non-residential baseline study data for Ameren Missouri showing the number of thermostats per customer.

Useful Lives of Load Control Devices and Smart Meters

The useful life of a load control switch is assumed to be 10 years[70]. This life was used for all direct load control measures in this study. Smart meters used for rate programs in this study are assumed to have a useful life of 20 years[71]. Smart thermostats are assumed to have a useful life of 10 years[72].

8.3.4 Customer Participation

The assumed level of customer participation (take rate) for each DR program option is a key driver of achievable DR potential estimates. Customer take rates reflect the total number of eligible customers that are likely to participate in a DR program. An eligible customer is defined as a customer that is eligible to participate in a DR program. For DLC programs, eligibility is determined by whether or not a customer has the end use equipment that will be controlled. For rate programs, eligibility can be limited by such parameters as rate schedule or type of meter. For example, only residential and non-residential SGS customers with smart meters are eligible for the CPP rate.

Existing Demand Response Programs

At the time that this study was conducted, Ameren Missouri was not offering any demand response programs to its customers.

Eligible Market Size

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64 Based on Ameren MO 2011 peak data

65 2013 Enernoc Study; PG&E and SCE CPP rate schedule: 4 hour periods, max of 15 events per year

66 The figure of 80 hours a year was obtained by GDS from "The Potential Impact of Demand-Side Rates for Ameren Missouri", prepared by The Brattle Group, Stakeholder Webinar, May 24, 2013; slide 43. According to a 2015 "Smart Rate Design" report published by the Regulatory Assistance Project, residential inclining block rates typically are designed so that every month the tail block of the energy charge rate structure charges a higher energy charge than for other usage blocks to reflect the long-run marginal costs for clean power resources as well as costs for new transmission and distribution infrastructure.

67 Every day, 4.1 hours per day from the National Electric Code Article 625

68 5 hours per day, weekdays all year

69 EIA RECS table HC6.1

70 Freeman, Sullivan & Co Cost Effectiveness of CECONY Demand Response Programs 2013; PA Act 129 Order 2013

71 Ameren Illinois AMI Cost/Benefit Analysis, 2012

72 Illinois Technical Reference Manual 2016

Table 8-5 through Table 8-10 provide information on the size of the eligible markets for residential, commercial, and industrial DR program options for both Achievable and Program MAP and RAP. For the DR rate programs that do not require an additional smart meter to be installed (such as the Critical Peak Pricing rate) all customers on applicable rate schedules were assumed to be eligible. Ameren Missouri expects to install smart meters during the planning horizon, but the project has not yet been approved. After discussion with Ameren Missouri, it was agreed that GDS would assume full deployment of smart meters 10 years into the study (2028), with a 10% deployment rate per year starting in 2019. These deployment rates were applied to the eligible customers for those rate programs that require smart meters.[73]

For direct load control programs, the size of the eligible market was determined by multiplying GDS' forecast of customers by the saturation of the end use to be controlled. End use saturations were obtained from a survey conducted by EnerNOC in 2013, along with profiles generated for Ameren by EnerNOC. This was done for each year through 2036. The number of eligible customers in each program and the source for each program's saturation is included in Appendix D.

Table 8-5// Eligible Residential Customers for MAP and Program MAP in Each DR Program Option

DR Program Option	Saturation / Hierarchy
Critical Peak Pricing Rate with Enabling Technology	86% of Residential Customers with smart meters (91% Central AC Saturation * 95% of Customers are Offered LC Device)
Critical Peak Pricing Rate without Enabling Technology	100% of Residential Customers with smart meters minus CPP with Tech Participants
Time of Use Rate without Enabling Technology	100% of Residential Customers minus all cost-effective CPP and TOU with Technology Participants
Inclining Block Rate	100% of Residential Customers minus all cost-effective CPP and TOU Participants
DLC Central AC Switch	91% of Residential Customers minus all cost-effective CPP, TOU, and IBR Participants
Plug-In Electric Vehicle Charging Stations Off Peak	100% of PEVs (20% Commercial, 80% Residential)

Table 8-6// Eligible Residential Customers for RAP and Program RAP in Each DR Program Option

DR Program Option	Saturation / Hierarchy
Critical Peak Pricing Rate with Enabling Technology	86% of Residential Customers with smart meters (91% Central AC Saturation * 95% of Customers are Offered LC Device)
Critical Peak Pricing Rate without Enabling Technology	100% of Residential Customers with smart meters minus CPP with Tech Participants
Time of Use Rate with Enabling Technology	86% of Residential Customers with smart meters (91% Central AC Saturation * 95% of Customers are Offered LC Device) minus all CPP Participants
Time of Use Rate without Enabling Technology	100% of Residential Customers minus all cost-effective CPP and TOU with Technology Participants

[73] 4 CSR 240-22.050(3)(D)

DR Program Option	Saturation / Hierarchy
Inclining Block Rate	100% of Residential Customers minus all cost-effective CPP and TOU Participants
DLC Central AC by Switch	91% of Residential Customers minus all cost-effective CPP, TOU, and IBR Participants
DLC Central AC by Smart Thermostat	55.5% of Residential Customers (91% CAC Saturation * 61% WiFi Saturation) minus all cost-effective CPP, TOU, and IBR Participants. Note, the WiFi saturation estimate was obtained from https://techcrunch.com/2012/04/05/study-61-of-u-s-households-now-have-wifi/
DLC Pool Pumps	5.5% of Residential Customers minus all cost-effective CPP, TOU, and IBR Participants
DLC Room AC	9% of Residential Customers minus all cost-effective CPP, TOU, and IBR Participants
DLC Electric Water Heaters	48% of Residential Customers minus all cost-effective CPP, TOU, and IBR Participants
DLC Smart Appliances	20% of Central AC Switch Participants with smart meters (Saturations of Each Appliance Included in Load Reduction Value) minus all cost-effective CPP, TOU, and IBR Participants
Off Peak Plug-In Electric Vehicle Charging Rate	100% of PEVs (20% Commercial, 80% Residential)

Table 8-7// Eligible Commercial Customers for MAP and Program MAP in Each DR Program Option

DR Program Option	Saturation / Hierarchy
Critical Peak Pricing Rate with Enabling Technology	77% of Commercial SGS, LGS, and SPS Customers with smart meters (80.85% Central AC Saturation * 95% of Customers are Offered LC Device)
Critical Peak Pricing Rate without Enabling Technology	100% of Commercial SGS, LGS, and SPS Customers with smart meters minus CPP with Technology Participants
DLC Central AC- One-Way Switch	80.85% of Commercial SGS Customers minus all cost-effective CPP and TOU Participants
DLC AC - Smart Controllable Thermostats	49.3% of Commercial SGS Customers (80.85% CAC Saturation * 61% WiFi Saturation) minus all cost-effective CPP and TOU Participants
Capacity Bidding	100% of Commercial LGS, SPS, and LPS Customers with smart meters minus all cost-effective CPP, TOU, and DLC Participants
Demand Bidding	100% of Commercial SGS Customers with smart meters minus all cost-effective CPP, TOU, DLC, and Capacity Bidding Participants

Table 8-8// Eligible Commercial Customers for RAP and Program RAP in Each DR Program Option

DR Program Option	Saturation / Hierarchy
Critical Peak Pricing Rate with Enabling Technology	77% of Commercial SGS, LGS, and SPS Customers with smart meters (80.85% Central AC Saturation * 95% of Customers are Offered LC Device)
Critical Peak Pricing Rate without Enabling Technology	100% of Commercial SGS, LGS, and SPS Customers with smart meters minus CPP with Technology Participants

DR Program Option	Saturation / Hierarchy
Time of Use Rate with Enabling Technology	77% of Commercial SGS Customers with smart meters (80.85% Central AC Saturation * 95% of Customers are Offered LC Device) minus all CPP Participants
Time of Use Rate without Enabling Technology	100% of Commercial SGS Customers minus all cost-effective CPP and TOU with Technology Participants
Interruptible Rate	100% of Commercial LGS and SPS Customers with smart meters minus all cost-effective CPP and TOU Participants
Thermal Electric Storage-Cooling Rate	2.41% of Commercial SGS, LGS, and SPS Customers minus all cost-effective CPP and TOU Participants
Off Peak Golf Cart Charging	100% of Golf Courses in Ameren's Service Area
Off Peak Utility Vehicle Charging	100% of Electric Commercial Utility Vehicles in Ameren's Service Area
Off Peak Plug-In Electric Vehicle Charging Rate	100% of PEVs (20% Commercial, 80% Residential)
DLC Central AC by Switch	80.85% of Commercial SGS Customers minus all cost-effective CPP and TOU Participants
DLC Central AC by Smart Thermostat	49.3% of Commercial SGS Customers (80.85% CAC Saturation * 61% WiFi Saturation) minus all cost-effective CPP and TOU Participants
DLC Lighting	25.5% of Industrial SGS Customers (Customers with T12 Lighting)
DLC Electric Water Heaters	28% of Commercial SGS Customers minus all cost-effective CPP and TOU Participants
DLC Pool Pumps	4.6% of Commercial SGS Customers minus all cost-effective CPP and TOU Participants
DLC Room AC	5% of Commercial SGS Customers minus all cost-effective CPP and TOU Participants
DLC Irrigation- Agriculture	100% of Irrigated Farms in Ameren's Service Area minus all cost-effective CPP and TOU Participants
Capacity Bidding	100% of Commercial LGS, SPS, and LPS Customers with smart meters minus all cost-effective CPP, TOU, and DLC Participants
Demand Bidding	100% of Commercial SGS, LGS, SPS, and LPS Customers with smart meters minus all cost-effective CPP, TOU, DLC, and Capacity Bidding Participants

Table 8-9 / / Eligible Industrial Customers for MAP and Program MAP in Each DR Program Option

DR Program Option	Saturation / Hierarchy
Critical Peak Pricing Rate with Enabling Technology	20% of Commercial SGS, LGS, and SPS Customers with smart meters (21% Central AC Saturation * 95% of Customers are Offered LC Device)
Critical Peak Pricing Rate without Enabling Technology	100% of Industrial SGS, LGS, and SPS Customers with smart meters minus CPP with Technology Participants
Interruptible Rate	100% of Industrial LGS and SPS Customers with smart meters minus all cost-effective CPP and TOU Participants

Capacity Bidding	100% of Industrial LGS, SPS, and LPS Customers with smart meters minus all cost-effective CPP, TOU, Interruptible, and DLC Participants
Demand Bidding	100% of Industrial SGS, LGS, SPS, and LPS Customers with smart meters minus all cost-effective CPP, TOU, Interruptible, and DLC Participants

Table 8-10// Eligible Industrial Customers for RAP and Program RAP in Each DR Program Option

DR Program Option	Saturation / Hierarchy
Critical Peak Pricing Rate with Enabling Technology	20% of Commercial SGS, LGS, and SPS Customers with smart meters (21% Central AC Saturation * 95% of Customers are Offered LC Device)
Critical Peak Pricing Rate without Enabling Technology	100% of Industrial SGS, LGS, and SPS Customers with smart meters minus CPP with Technology Participants
Time of Use Rate with Enabling Technology	20% of Commercial SGS Customers with smart meters (21% Central AC Saturation * 95% of Customers are Offered LC Device) minus all cost-effective CPP Participants
Time of Use Rate without Enabling Technology	100% of Industrial SGS Customers minus all cost-effective CPP and TOU with Technology Participants
Interruptible Rate	100% of Industrial LGS and SPS Customers with smart meters minus all cost-effective CPP and TOU Participants
Thermal Electric Storage-Cooling Rate	2.41% of Industrial SGS, LGS, and SPS Customers minus all cost-effective CPP, TOU, and Interruptible Participants
Off Peak Utility Vehicle Charging	100% of Electric Industrial Utility Vehicles in Ameren's Service Area
DLC Central AC by Switch	21% of Industrial SGS Customers minus all cost-effective CPP, TOU, and Interruptible Participants
DLC Central AC by Smart Thermostat	12.8% of Industrial SGS Customers (21% CAC Saturation * 61% WiFi Saturation) minus all cost-effective CPP, TOU, and Interruptible Participants
DLC Lighting	24.1% of Industrial SGS Customers (Customers with T12 Lighting) minus all cost-effective CPP, TOU, and Interruptible Participants
DLC Electric Water Heaters	28% of Industrial SGS Customers minus all cost-effective CPP, TOU, and Interruptible Participants
DLC Room AC	5% of Industrial SGS Customers minus all cost-effective CPP, TOU, and Interruptible Participants
Capacity Bidding	100% of Industrial LGS, SPS, and LPS Customers with smart meters minus all cost-effective CPP, TOU, Interruptible, and DLC Participants
Demand Bidding	100% of Industrial SGS, LGS, SPS, and LPS Customers with smart meters minus all cost-effective CPP, TOU, Interruptible, and DLC Participants

Hierarchy

Double-counting savings from DR programs that affect the same end uses is a common issue that must be addressed when calculating the DR savings potential. For example, a customer cannot elect to participate in both DLC options and rate programs, and claim savings from both programs for curtailing the same end use. GDS has determined a hierarchy for our analytical approach to ensure that this does not occur. This hierarchy establishes the type of DR program that is assumed to be selected by an eligible customer if the customer has the option to participate in more than one DR program that affects the same end use. For some non-residential rate based DR program options, eligible customers were limited. For example, a special TOU rate for golf cart charging is limited to the number of golf course customers in the Ameren Missouri service area. Other examples of limited customer eligibility for rate based DR program options include Interruptible Rates and a special TOU rate for plug-in electric vehicles.

In general, the hierarchy of DR program options is accounted for by subtracting the number participants in a higher priority, cost-effective program such as a CPP rate from the eligible customers in a lower priority program such as direct load control of air conditioning. This hierarchy was determined by GDS with input from Ameren Missouri. Rate options are first in priority because they offer more customer choice and result in greater customer comfort and satisfaction. Demand response rates give customers the option regarding whether or not they want to reduce or shift their load, as opposed to the equipment or appliance being controlled by the utility. A hierarchy was also developed within the rate options because it was assumed that customers cannot participate in more than one rate program. This hierarchy is based on the biggest dollar savings (benefits minus costs) for each program before the hierarchy was applied. Direct load control programs are all the same priority, because customers are able to participate in more than one program option at a time if they have multiple end-use that can be controlled. Refer to Table 8-11 for the specific hierarchy levels for each demand response option.

In the MAP scenario, an opt-out DR rate program is the default option for participation, assuming that the customer has a smart meter.

Table 8-11// Hierarchy for Demand Response Programs[74]

Customer Class	Priority	DR Measure
Residential	1	Critical Peak Pricing with Enabling Technology
	2	Critical Peak Pricing without Enabling Technology
	3	Time of Use with Enabling Technology
	4	Time of Use without Enabling Technology
	5	Inclining Block Rate
	6	Direct Load Control
Commercial and Industrial	1	Critical Peak Pricing with Enabling Technology
	2	Critical Peak Pricing without Enabling Technology
	3	Interruptible Rate
	4	Time of Use with Enabling Technology
	5	Time of Use without Enabling Technology
	6	Direct Load Control
	7	Capacity Bidding & Demand Bidding

In some cases, a program that is higher in the hierarchy, may have no impact on a lower ranked program. For example, a customer that participates in an off-peak electric vehicle charging program can also participate in an air conditioning direct load control program. These types of judgements were made for each DR program option that was analyzed to eliminate any double counting of DR potential.

Take Rates

[74] 4 CSR 240-22.050(1)(C); 4 CSR 240-22.050(4)(D)2

The assumed "steady state" take rates used in this potential study and the sources upon which each assumption is based are shown in Table 8-12 for residential and non-residential customers, respectively. The steady state take rate represents the annual enrollment rate once the fully achievable participation has been reached. Take rates are expressed as a percentage of eligible customers. Program participation and impacts (demand reductions) are assumed to begin in 2019. Take rates and sources are shown in Appendix D.

Two sets of take rates were developed for each DR program option. One for the RAP scenario and the other for the MAP scenario:

- RAP take rates for DLC programs generally represent a level of customer participation that is at the median or 50th percentile of industry program performance. For DR rate programs, the RAP take rates are taken from various secondary research sources and are considered to represent an average level of participation for an opt-in rate. An opt-in rate means that customers would remain on their existing rate and would need to proactively enroll in the DR rate. For Aggregator programs, the RAP take rates are based on recent experience with such programs in California.
- MAP take rates for DLC programs generally represent a level of customer participation that is at the 75th percentile of industry program performance. For DR rate programs the MAP take rates are taken from various secondary research sources and are considered to represent an average level of participation for an opt-out rate. An opt-out rate means that customers are automatically enrolled in a DR rate, but can revert back to the otherwise applicable tariff if they choose. Opt-out rate offerings will result in significantly higher enrollment compared to opt-in rate offerings. For Aggregator programs, the MAP take rates are based on secondary research indicating the stated level of interest in such programs.

Customer participation in DR programs is assumed to reach the steady state take rate over a five-year period. The path to steady state customer participation follows an "S-shaped" curve, in which participation growth accelerates over the first half of the five-year period, and then slows over the second half of the period (see Figure 8-2). A similar (inverse) S-shaped curve is used to account for the rate at which customers opt-out of DR rate options over the five-year period.

Figure 8-2// Illustration of S-Shaped Market Adoption Curve

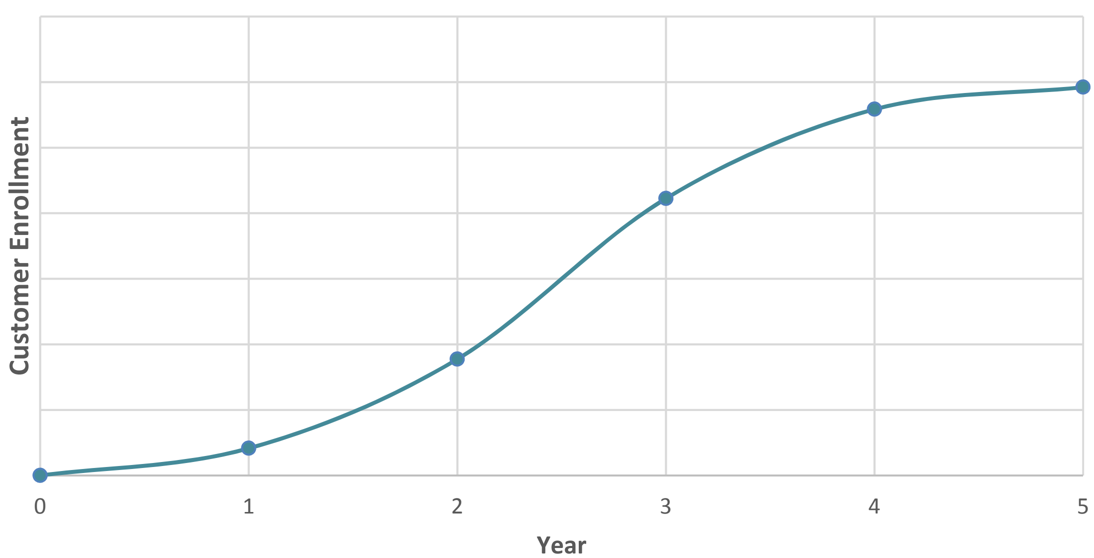


Table 8-12// Steady State Take Rates for Residential DR Program Options

DR Option	RAP Take Rate	MAP Take Rate
RESIDENTIAL		
Direct Load Control		
Direct Load Control - Central Air Conditioning	20%	31%
Direct Load Control - Water Heating	23%	36%
Direct Load Control - Swimming Pool Pumps	19%	38%
Direct Load Control - Smart Appliances	20%	31%
Direct Load Control - Room Air Conditioning	20%	31%
Direct Load Control of Central AC w/Smart Thermostat	25%	36%
Rate Options		
Time of Use Rate w/o Enabling Technology	28%	85%
Time of Use Rate with Enabling Technology	36%	94%
Critical Peak Pricing Rate w/o Enabling Technology	17%	82%
Critical Peak Pricing Rate with Enabling Technology	22%	91%
Inclining Block Rate	20%	75%
Off Peak Charging of Personal Electric Vehicles - TOU Rate	57%	94%
NON-RESIDENTIAL		
Direct Load Control		
Direct Load Control - Central Air Conditioning	3%	14%
Direct Load Control - Water Heating	7%	16%
Direct Load Control - Room Air Conditioners	3%	14%
Direct Load Control - Swimming Pool Pumps	7%	16%
Direct Load Control - Commercial and Industrial Lighting	3%	14%
Direct Load Control - Agricultural Irrigation Pump	15%	30%
Direct Load Control of Central AC w/Smart Thermostat	8%	19%
Rate Options		
Base Interruptible Program	3%	21%
Time of Use Rate w/o Enabling Technology	13%	74%
Time of Use Rate with Enabling Technology	16%	81%
Electric Thermal Storage – Cooling Rate	16%	81%
Critical Peak Pricing Rate w/o Enabling Technology	18%	63%
Critical Peak Pricing Rate with Enabling Technology	20%	69%
Off Peak Charging of Golf Carts - TOU Rate	16%	81%

DR Option	RAP Take Rate	MAP Take Rate
Off Peak Charging of Other Plug-In Utility Vehicles - TOU Rate	16%	81%
Off Peak Charging of Electric Feet Vehicles - TOU Rate	60%	94%
Aggregator Programs		
Capacity Bidding Programs	1%	8%
Demand Bidding Programs	1%	10%

8.3.5 Load Reduction Assumptions

Table 8-13 and Table 8-14 present the residential and non-residential per participant CP demand reduction impact assumptions for each DR program option. Since there are no existing DR programs at Ameren Missouri, demand reduction impacts are based on various secondary data sources including the Federal Regulatory Energy Commission (FERC) and other industry reports, including DR potential studies. Specific sources used for each DR program option can be found in Appendix D.

Table 8-13// Residential Per Participant CP Demand Reduction Assumptions

DR Program Options	Per Participant CP Demand Reduction	Unit of Impact
Direct Load Control		
Control of Central Air Conditioners with Load Control Switch	1.06 kW	kW load reduction per customer (summer)
Control of Electric Water Heaters	0.4 kW	kW load reduction per customer (summer)
Control of Room Air Conditioners	0.504 kW	kW load reduction per customer (summer)
Control of Swimming Pool Pumps	1.36 kW	kW load reduction per customer (summer)
Control of Air Conditioners with Controllable "Smart" Thermostats (i.e. Nest, Ecobee)	0.92 kW	kW load reduction per customer (summer)
Smart Appliances	0.072 kW	kW load reduction per customer (summer)
Rate Options		
Time of Use Rate w/o Enabling Technology	3.20%	Per customer % impact
Time of Use Rate with Enabling Technology for Smart Appliances	6.08%	Per customer % impact
Critical Peak Pricing Rate w/o Enabling Technology	12.95%	Per customer % impact
Critical Peak Pricing Rate with Enabling Technology for Smart Appliances	23.44%	Per customer % impact
Electric Vehicle Charging Station Off Peak (Personal and Fleet)	0.94 kW	kW load reduction per customer (summer)
Inclining Block Rate	4.40%	Per customer % impact

Table 8-14// Non-Residential Per Participant CP Demand Reduction Assumptions

Demand Response Measures	Per Participant CP Demand Reduction	Unit of Impact
Direct Load Control		

Demand Response Measures	Per Participant CP Demand Reduction	Unit of Impact
Control of Central Air Conditioners with Load Control Switch	1.6 kW	kW load reduction per customer (summer)
Control of Electric Water Heaters	0.9 kW	kW load reduction per customer (summer)
Control of Room Air Conditioners	0.761 kW	kW load reduction per customer (summer)
Electric Thermal Storage – Cooling	19.4 kW (buildings with chillers)	kW load reduction per customer (summer)
Control of Swimming Pool Pumps	2 kW	kW load reduction per customer (summer)
Control of Commercial Lighting - On/Off, Dimming	8.75% of total CP demand	Per customer % impact
Agricultural Irrigation Pump Control	44 kW	kW load reduction per customer (summer)
Control of Air Conditioners with Controllable "Smart" Thermostats (i.e. Nest, Ecobee)	1.4 kW	kW load reduction per customer (summer)
Rate Options		
Interruptible Rate	41.3 KW	kW load reduction per customer (summer)
Time of Use Rate w/o Enabling Technology	2%	Per customer % impact
Time of Use Rate with Enabling Technology	3.80%	Per customer % impact
Critical Peak Pricing Rate w/o Enabling Technology	11.30%	Per customer % impact
Critical Peak Pricing Rate with Enabling Technology	21.47%	Per customer % impact
Off Peak Charging of Golf Carts	0.75 kW per cart	kW load reduction per customer (summer)
Off Peak Charging of Other Plug-In Utility Vehicles	1.7 kW per utility vehicle	kW load reduction per customer (summer)
Electric Vehicle Charging Station Off Peak (Personal and Fleet)	0.94 kW	kW load reduction per customer (summer)
Aggregator Programs		
Capacity Bidding Programs	19.50%	Per customer % impact
Demand Bidding Programs	7%	Per customer % impact

8.3.6 Program Costs

Table 8-15 shows the program costs that were assumed for each DR program option. It was generally assumed that there would be one program manager for each sector's DLC and rate programs, and one engineer and one engineering assistant working on all of the DLC programs for each sector. At the request of Ameren Missouri, we have assumed that DR options would be delivered by vendors.

There are one-time program development costs for new programs that are included in the first year of the analysis. No program development costs are assumed for TOU because TOU rates are currently offered by Ameren Missouri. The Notes column in Table 8-15 provides detail on how costs were allocated amongst programs. Each program includes a $50,000/year evaluation cost. It was assumed that there would be a cost of $50[75] per new participant for marketing. Marketing costs are assumed to be 33.3% higher for MAP for those programs that are opt-in. Opt-out rate programs do not have any marketing cost. All program costs were escalated each year by the general rate of inflation assumed for this study.[76] For our analysis, expenditures on direct load control computer equipment and load control switches were not amortized over the life of the equipment.

The total cost to Ameren Missouri per customer for DLC equipment was assumed to be $70 for the one-way switch and $200 for installation[77] for the installation of the DLC switch. This cost is based on a large volume of load control switches being supplied to a utility. GDS assumed a one-way communicating switch for this study, because it is the most cost-effective. The equipment cost of a smart controllable thermostat (such as a Nest or Ecobee) is $249. Installation labor for the thermostat is assumed to be $250[78]. CPP and TOU rates with enabling technologies also assumed a smart thermostat would be given to the customer. Rate programs that require smart meters were assumed to have no equipment cost, because Ameren will have already installed the smart meters required for these programs. The TOU without enabling technologies program does not require a smart meter, but it does require a meter that is able to support TOU. The cost used for this TOU meter is $236 and the handling and installation cost is approximately $90[79]. There were assumed to be no equipment cost for the Demand Bidding program, as it will use existing smart meters. The Capacity Bidding commercial program used $1,112 per customer for the enabling technology costs and the industrial program used $1,462 per customer[80].

An initial central controller hardware with an assumed cost of $25,000 is needed at the start of each program and is assumed to be replaced after 10 years, with an additional $5,000 per year (plus inflation) for software updates. This is only for DLC programs (including control of thermostats), not rate programs. For non-residential programs that include both the commercial and industrial sectors, these central controller costs are split evenly between the sectors.

An operation and maintenance (O&M) cost was included for 2-way communicating devices. This is only smart thermostats in this study. The O&M cost was assumed to be 5% of equipment and installation costs for the thermostats per participant per year.[81]

Table 8-15 // Program Cost Assumptions

Sector	Demand Response Program	Consulting Cost to Run Program[82]	Program Development Cost[83]	Evaluation Cost[84]	Marketing[85, 86]	Notes

[75] TVA POTENTIAL STUDY VOLUME 3: DEMAND RESPONSE POTENTIAL STUDY, Global Energy partners, December 2011
[76] The general rate of inflation used for this study was 2%. This was provided by Ameren Missouri.
[77] Costs of switch provided by Comverge, Angel Sustaeta
[78] Thermostat costs taken from Nest and Ecobee websites
[79] TOU meter and installation costs provided by Ameren for a Landis&Gyr S4X meter
[80] Based on the 2011 TVA potential study and the equipment costs used in the 2013 Ameren MO potential study. GDS took weighted average using numbers of customers in each rate class.
[81] AEG PacifiCorp Demand-Side Resource Potential Assessment for 2015-2034 Volume 5 Appendix. January 2015.
[82] Assumes one senior project manager overseeing each of the residential and non-residential sectors, one associate engineer and one engineering assistant working on all of the DLC programs for each sector. All consultants are assumed to work 20 hours per week. These consultants are billed at GDS rates.
[83] Based on GDS Experience and Tennessee Valley Authority Potential Study Volume 3: Demand Response Potential Study, Global Energy Partners, 2011.
[84] Based on GDS Experience and Tennessee Valley Authority Potential Study Volume 3: Demand Response Potential Study, Global Energy Partners, 2011.
[85] Based on GDS Experience and Tennessee Valley Authority Potential Study Volume 3: Demand Response Potential Study, Global Energy Partners, 2011.
[86] MAP marketing costs for programs that are not opt-out rates are 33% higher than RAP. MAP opt-out rates assume $0 for marketing costs.

Sector	Demand Response Program	Consulting Cost to Run Program[82]	Program Development Cost[83]	Evaluation Cost[84]	Marketing[85, 86]	Notes
Residential	DLC Central AC by Switch	$64,763	$80,000 (one year only)	$50,000	$50 per participant	$400,000 Program Development between Residential DLC Switch Options
	DLC Central AC by Controllable Thermostat	$64,763	$200,000 (one year only)	$50,000	$50 per participant	N/A
	DLC Room AC	$64,763	$80,000 (one year only)	$50,000	$50 per participant	$400,000 Program Development between Residential DLC Switch Options
	DLC Electric Water Heaters	$64,763	$80,000 (one year only)	$50,000	$50 per participant	$400,000 Program Development between Residential DLC Switch Options
	DLC Pool Pumps	$64,763	$80,000 (one year only)	$50,000	$50 per participant	$400,000 Program Development between Residential DLC Switch Options
	DLC Appliances	$64,763	$80,000 (one year only)	$50,000	$50 per participant	$400,000 Program Development between Residential DLC Switch Options
	CPP with Enabling Technology	$23,163	$100,000 (one year only)	$50,000	$50 per participant	$200,000 split between Residential CPP Options
	CPP without Enabling Technology	$23,163	$100,000 (one year only)	$50,000	$50 per participant	$200,000 split between Residential CPP Options
	TOU with Enabling Technology	$23,163	$0 (existing rate)	$50,000	$50 per participant	N/A
	TOU without Enabling Technology	$23,163	$0 (existing rate)	$50,000	$50 per participant	N/A

Sector	Demand Response Program	Consulting Cost to Run Program[82]	Program Development Cost[83]	Evaluation Cost[84]	Marketing[85, 86]	Notes
	Inclining Block Rate	$23,163	$100,000 (one year only)	$50,000	$50 per participant	N/A
	Off-Peak PEV Charging	$23,163	$100,000 (one year only)	$50,000	$50 per participant	$400,000 Split between PEV Residential, PEV Commercial, Golf Cart Charging, & Utility Vehicle Charging
Non-Residential[87]	CPP with Enabling Technology	$14,988	$100,000 (one year only)	$50,000	$50 per participant	$200,000 split between Non-Residential CPP Options
	CPP without Enabling Technology	$14,988	$100,000 (one year only)	$50,000	$50 per participant	$200,000 split between Non-Residential CPP Options
	TOU with Enabling Technology	$14,988	$0 (existing rate)	$50,000	$50 per participant	N/A
	TOU without Enabling Technology	$14,988	$0 (existing rate)	$50,000	$50 per participant	N/A
	Off-Peak PEV Charging	$14,988	$100,000 (one year only)	$50,000	$50 per participant	$400,000 Split between PEV Residential, PEV Commercial, Golf Cart Charging, & Utility Vehicle Charging
	Off-Peak Golf Cart Charging	$14,988	$100,000 (one year only)	$50,000	$50 per participant	$400,000 Split between PEV Residential, PEV Commercial, Golf Cart Charging, & Utility Vehicle Charging
	Off-Peak Electric Utility Vehicle Charging	$14,988	$100,000 (one year only)	$50,000	$50 per participant	$400,000 Split between PEV Residential, PEV Commercial, Golf Cart Charging, &

[87] For non-residential programs that are both commercial and industrial, consulting, program development, and evaluation costs are split in half between commercial and industrial.

Sector	Demand Response Program	Consulting Cost to Run Program[82]	Program Development Cost[83]	Evaluation Cost[84]	Marketing[85, 86]	Notes
						Utility Vehicle Charging
	Thermal Electric Storage-Cooling Rate	$14,988	$100,000 (one year only)	$50,000	$500[88] per participant	N/A
	Interruptible Rate	$14,988	$50,000 (one year only)	$0	$500 per participant	N/A
	Capacity Bidding	$14,988	$200,000 (one year only)	$50,000	$500 per participant	N/A
	Demand Bidding	$14,988	$200,000 (one year only)	$50,000	$50 per participant	N/A
	DLC Central AC by Switch	$49,655	$80,000 (one year only)	$50,000	$50 per participant	$400,000 Program Development between Non-Residential DLC Switch Options
	DLC Central AC by Controllable Thermostat	$49,655	$200,000 (one year only)	$50,000	$50 per participant	N/A
	DLC Room AC	$49,655	$80,000 (one year only)	$50,000	$50 per participant	$400,000 Program Development between Non-Residential DLC Switch Options
	DLC Electric Water Heaters	$49,655	$80,000 (one year only)	$50,000	$9 per participant	$400,000 Program Development between Non-Residential DLC Switch Options
	DLC Pool Pumps	$49,655	$80,000 (one year only)	$50,000	$50 per participant	$400,000 Program Development between Non-Residential DLC Switch Options
	DLC Commercial Lighting	$49,655	$80,000 (one year only)	$50,000	$50 per participant	$400,000 Program Development between Non-

88 Programs with large customers were assumed to have a higher marketing cost per customer. Based on GDS Experience and Tennessee Valley Authority Potential Study Volume 3: Demand Response Potential Study, Global Energy Partners, 2011.

Sector	Demand Response Program	Consulting Cost to Run Program[82]	Program Development Cost[83]	Evaluation Cost[84]	Marketing[85, 86]	Notes
						Residential DLC Switch Options
	DLC Irrigation-Agriculture	$49,655	$100,000 (one year only)	$50,000	$50 per participant	N/A

Non-equipment incentives were added to the GDS DR model, but those incentives were not included in the TRC calculation. However, they were used to create program budgets. Table 8-16 shows the incentives used.

Table 8-16 // Non-Equipment Incentives

DR Program Option	Residential	Source	Commercial	Source	Industrial	Source
DLC AC - Switch	$27.33/ participant	Average of 9 utilities in MISO territory with 50% cycling DLC AC programs	$60/ participant	Assumes $15/month incentive for AC, for 4 summer months (June-September) (Incentive assumed to be $5/ton/month; average small commercial AC tonnage assumed to be 3 tons)	$60/ participant	Assumes $15/month incentive for AC, for 4 summer months (June-September) (Incentive assumed to be $5/ton/month; average small commercial AC tonnage assumed to be 3 tons)
Capacity Bidding	N/A	N/A	$50/kW-yr and $0.03/kWh	Based on TVA 2011 Potential Study, KCP&L 2013 Demand Side Resource Potential Study, LMP data for MISO in MO	$50/kW-yr and $0.03/kWh	Based on TVA 2011 Potential Study, KCP&L 2013 Demand Side Resource Potential Study, LMP data for MISO in MO
Demand Bidding	N/A	N/A	$0.5/kWh	PG&E Program	$0.5/kWh	PG&E Program
DLC WH	$8/ participant	LG&E/KU Program	$17.56/ participant	Water heater incentive level for is assumed to scale up by the same ratio as that for AC, in comparison with residential customers	$17.56/ participant	Water heater incentive level for is assumed to scale up by the same ratio as that for AC, in comparison with residential customers

DR Program Option	Residential	Source	Commercial	Source	Industrial	Source
DLC PP	$8/ participant	LG&E/KU Program	$17.56/ participant	Water heater incentive level for is assumed to scale up by the same ratio as that for AC, in comparison with residential customers	N/A	N/A
Interruptible Rate	N/A	N/A	$8.5/kW-yr	PG&E Program	$8.5/kW-yr	PG&E Program

8.4 TECHNICAL, ECONOMIC, ACHIEVABLE, PROGRAM POTENTIAL RESULTS[89]

This section provides the cost-effectiveness results for MAP, RAP, Program MAP, and Program RAP. The DR potential results are also provided for each sector.

8.4.1 Residential Demand Response Potential

Table 8-17 and Table 8-18 show the MAP and RAP residential net present values of the total benefits, costs, and savings, along with the TRC ratio for each program. MAP benefit-cost analyses are only shown for programs that had a TRC ratio of 0.95 or higher for RAP.

Table 8-17// Residential MAP NPV Benefits, Costs, Savings, and TRC Ratios for Each Demand Response Program ($ in Millions)

Demand Response Option	NPV Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
Critical Peak Pricing Rate with Enabling Technology	$598	$490	$108	1.22
Critical Peak Pricing Rate without Enabling Technology	$303	$1	$302	280.19
Time of Use Rate without Enabling Technology	$73	$307	($234)	0.24
Inclining Block Rate	$92	$1	$91	84.91
DLC Central AC Switch	$3	$6	($3)	0.44
Plug-In Electric Vehicle Charging Stations Off Peak	$15	$11	$5	1.41

Table 8-18// Residential RAP NPV Benefits, Costs, Savings, and TRC Ratios for Each Demand Response Program ($ in Millions)

Demand Response Option	NPV Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio

[89] 4 CSR 240-22.050(5)(D); 4 CSR 240-22.050(5)(E)

Demand Response Option	NPV Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
Critical Peak Pricing Rate with Enabling Technology	$233	$202	$31	1.15
Critical Peak Pricing Rate without Enabling Technology	$94	$7	$86	12.8
Time of Use Rate with Enabling Technology	$62	$206	($145)	0.3
Time of Use Rate without Enabling Technology	$44	$89	($45)	0.5
Inclining Block Rate	$43	$9	$34	4.61
DLC Central AC Switch	$234	$61	$173	3.85

Table 8-19 and Table 8-20 show the Program MAP and RAP residential net present values of the total benefits, costs, and savings, along with the TRC ratio for each program. Programs were only looked at for Program Potential if they were cost-effective in MAP or RAP potential.

Table 8-19// Residential Program MAP NPV Benefits, Costs, Savings, and TRC Ratios for Each Demand Response Program($ in Millions)

Demand Response Option	NPV Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
Critical Peak Pricing Rate with Enabling Technology	$546	$490	$56	1.11
Critical Peak Pricing Rate without Enabling Technology	$277	$1	$276	255.68
Inclining Block Rate	$88	$1	$86	78.87
Plug-In Electric Vehicle Charging Stations Off Peak	$15	$11	$5	1.41

Table 8-20// Residential Program RAP NPV Benefits, Costs, Savings, and TRC Ratios for Each Demand Response Program ($ in Millions)

Demand Response Option	NPV Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
Critical Peak Pricing Rate with Enabling Technology	$216	$202	$14	1.07
Critical Peak Pricing Rate without Enabling Technology	$87	$7	$79	11.87
Inclining Block Rate	$41	$9	$31	4.32
Plug-In Electric Vehicle Charging Stations Off Peak	$8	$7	$1	1.19

Demand Response Option	NPV Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
DLC Central AC by Switch	$214	$61	$154	3.53
DLC Central AC by Smart Thermostat	$88	$76	$12	1.16

Table 8-21 and Table 8-22 show the residential technical, economic, achievable, and program potential for the Base Case and Smart Thermostat Scenario. Technical potential assumes 100% of eligible customers will participate in all programs starting in year 1, regardless of cost-effectiveness. Economic potential includes all programs that are considered cost-effective based on the TRC test. Economic potential, like technical potential, assumes that 100% of eligible customers will participate in programs starting in year 1. The achievable potentials include all cost-effective programs. However, achievable potential includes a take rate to estimate the number of customers that are expected to participate in each cost-effective DR program option. These DR potential values are at the customer meter.

Table 8-21// Summary of Cumulative Annual Residential Base Case Technical, Economic, Achievable, and Program Potential

Potential Level	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Technical	1,725	1,671	1,589	2,030	2,058
Economic	1,293	1,342	1,313	1,814	1,840
MAP	219	263	299	663	678
RAP	18	81	185	369	379
Program MAP	216	257	289	605	596
Program RAP	18	80	181	340	335

Table 8-22 // Summary of Cumulative Annual Residential Smart Thermostat Scenario Technical, Economic, Achievable, and Program Potential

Potential Level	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Technical	1,250	1,205	1,139	1,615	1,639
Economic	818	876	864	1,399	1,421
MAP	219	263	299	663	678
RAP	13	60	134	290	300
Program MAP	216	257	289	605	596
Program RAP	13	59	131	269	268

Table 8-23 and Table 8-24 show the residential maximum and realistic achievable potential for each program for the years 2019, 2020, 2021, 2028, and 2036. Those residential programs that are not listed were found to be not cost-effective, and therefore have no achievable potential.

Table 8-23// Summary of Cumulative Annual Maximum Achievable Residential Summer MW Savings by Program

DR Program	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Critical Peak Pricing Rate with Enabling Technology	46	90	130	426	430
Critical Peak Pricing Rate without Enabling Technology	24	46	67	216	218
Inclining Block Rate	148	125	100	12	12
Plug-In Electric Vehicle Charging Stations Off Peak	1	2	2	9	17
Total (Both Scenarios)	**219**	**263**	**299**	**663**	**678**

Table 8-24// Summary of Cumulative Annual Realistic Achievable Residential Summer MW Savings by Program

DR Program	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Critical Peak Pricing Rate with Enabling Technology	1	10	36	172	173
Critical Peak Pricing Rate without Enabling Technology	0	5	15	69	69
Inclining Block Rate	2	10	22	23	23
Direct Load Control (DLC) Central AC Switch	14	56	111	101	102
Direct Load Control (DLC) Central AC Thermostat	9	35	60	23	23
Plug-In Electric Vehicle Charging Stations Off Peak	0	0	1	4	11
Base Case Total	**18**	**81**	**185**	**369**	**379**
Smart Thermostat Scenario Total	**13**	**60**	**134**	**290**	**300**

Table 8-25 and Table 8-26 Table 8-23show the residential Program MAP and Program RAP potential for each program for the years 2019, 2020, 2021, 2028, and 2036. The program potential is lower than achievable potential because it captures the effects on DR from the more efficient equipment caused by energy efficiency programs.[90] Those residential programs that are not listed were found to be not cost-effective, and therefore have no program potential.

[90] 4 CSR 240-22.050(4)(D)3

Table 8-25// Summary of Cumulative Annual Residential Program MAP Summer MW Savings by Program

DR Program	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Critical Peak Pricing Rate with Enabling Technology	45	88	126	389	377
Critical Peak Pricing Rate without Enabling Technology	23	45	64	197	191
Inclining Block Rate	146	122	96	11	11
Plug-In Electric Vehicle Charging Stations Off Peak	1	2	2	9	17
Total (Both Scenarios)	**216**	**257**	**289**	**605**	**596**

Table 8-26// Summary of Cumulative Annual Residential Program RAP Summer MW Savings by Program

DR Program	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Critical Peak Pricing Rate with Enabling Technology	1	10	35	160	155
Critical Peak Pricing Rate without Enabling Technology	0	5	15	64	62
Inclining Block Rate	2	10	21	21	21
Direct Load Control (DLC) Central AC Switch	14	55	109	92	86
Direct Load Control (DLC) Central AC Thermostat	9	34	59	21	19
Plug-In Electric Vehicle Charging Stations Off Peak	0	0	1	4	11
Base Case Total	**18**	**80**	**181**	**340**	**335**
Smart Thermostat Scenario Total	**13**	**59**	**131**	**269**	**268**

8.4.2 Commercial Demand Response Potential

Table 8-27 and Table 8-28 show the MAP and RAP commercial sector net present values of the total benefits, costs, and savings, along with the TRC ratio for each program. MAP benefit-cost analyses are only shown for programs that had a TRC ratio of 0.95 or higher for RAP.

Table 8-27// Commercial MAP NPV Benefits, Costs, Savings, and TRC Ratios for Each Demand Response Program ($ in Millions)

Demand Response Option	NPV Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio

Demand Response Option	NPV Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
Critical Peak Pricing Rate with Enabling Technology	$285	$109	$175	2.61
Critical Peak Pricing Rate without Enabling Technology	$202	$0	$201	414.36
PEV Rate	$4	$3	$0	1.1
DLC Central AC- One-Way Switch	$12	$5	$6	2.18
Capacity Bidding	$13	$1	$12	14.4
Demand Bidding - Smart Thermostat Scenario	$2	$1	$1	2.76
Demand Bidding - Base Case	$2	$1	$1	2.5

Table 8-28// Commercial RAP NPV Benefits, Costs, Savings, and TRC Ratios for Each Demand Response Program ($ in Millions)

Demand Response Option	NPV Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
Critical Peak Pricing Rate with Enabling Technology	$131.74	$52.60	$79.13	2.5
Critical Peak Pricing Rate without Enabling Technology	$68.93	$1.99	$66.94	34.62
Time of Use Rate with Enabling Technology	$3.34	$24.27	($20.92)	0.14
Time of Use Rate without Enabling Technology	$2.81	$9.07	($6.26)	0.31
Thermal Electric Storage- Cooling Rate	$20.82	$45.70	($24.88)	0.46
Charging of Utility Vehicles Off Peak	$3.13	$12.46	($18.66)	0.25
Charging of Golf Carts Off Peak	$1.79	$5.29	($3.50)	0.34
Plug-In Electric Vehicle Charging Stations Off Peak	$1.97	$2.40	($0.44)	0.82
Interruptible Rate	$0.00	$0.46	($0.46)	0.01
Capacity Bidding	$4.55	$0.69	$3.85	6.56
Demand Bidding - Base Case	$0.61	$0.63	($0.03)	0.96
Demand Bidding - Thermostat Scenario	$2.08	$0.63	$1.45	3.28
DLC Central AC- One-Way Switch	$7.28	$1.82	$5.46	4
DLC AC - Smart Controllable Thermostats	$7.48	$8.09	($0.61)	0.92

Demand Response Option	NPV Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
DLC Lighting	$3.86	$11.91	($8.05)	0.32
DLC Pool Pumps	$0.02	$1.55	($1.53)	0.01
DLC Room AC	$0.35	$0.87	($0.52)	0.4
DLC Agricultural Irrigation	$0.01	$1.54	($1.54)	0.01
DLC Electric Water Heating	$0.66	$1.39	($0.72)	0.48

Table 8-29 and Table 8-30 show the Commercial Sector Program MAP and RAP net present values of the total benefits, costs, and savings, along with the TRC ratio for each program. Programs were only looked at for Program Potential if they were cost-effective in MAP or RAP potential.

Table 8-29// Commercial Program MAP NPV Benefits, Costs, Savings, and TRC Ratios for Each Demand Response Program ($ in Millions)

Demand Response Option	NPV Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
Critical Peak Pricing Rate with Enabling Technology	$243	$109	$134	2.23
Critical Peak Pricing Rate without Enabling Technology	$172	$0	$172	353.95
DLC Central AC by Switch	$11	$5	$5	1.99
Capacity Bidding	$11	$1	$10	12.22
Demand Bidding- Base Case	$2	$1	$1	2.1
Demand Bidding - Thermostat Scenario	$2	$1	$1	2.34
Plug-In Electric Vehicle Charging Stations Off Peak	$4	$3	$0	1.1

Table 8-30// Commercial Program RAP NPV Benefits, Costs, Savings, and TRC Ratios for Each Demand Response Program($ in Millions)

Demand Response Option	NPV Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
Critical Peak Pricing Rate with Enabling Technology	$118	$53	$66	2.25

Critical Peak Pricing Rate without Enabling Technology	$62	$2	$60	31.1
DLC Central AC by Switch	$7	$2	$5	3.83
Capacity Bidding	$4	$1	$3	5.9
Demand Bidding (Thermostat Scenario Only)	$2	$1	$1	2.95

Table 8-31 and Table 8-32 show the commercial sector technical, economic, achievable, and program potential for the Base Case and Smart Thermostat Scenario.

Table 8-31// Summary of Cumulative Annual Commercial Base Case Technical, Economic, Achievable, and Program Potential

Potential Level	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Technical	585	658	734	1,439	1,448
Economic	313	395	511	1,202	1,207
MAP	47	92	129	361	365
RAP	1	11	36	156	156
Program MAP	46	88	121	307	298
Program RAP	1	11	35	140	136

Table 8-32// Summary of Cumulative Annual Commercial Smart Thermostat Scenario Technical, Economic, Achievable, and Program Potential

Potential Level	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Technical	510	596	682	1,465	1,474
Economic	143	247	388	1,251	1,257
MAP	46	87	117	361	365
RAP	1	9	32	154	155
Program MAP	44	83	109	307	298
Program RAP	2	10	32	138	135

Table 8-33 and Table 8-34 show the commercial maximum and realistic achievable potential for each program for the years 2019, 2020, 2021, 2028, and 2036. Those commercial programs that are not listed were found to be not cost-effective, and therefore have no achievable potential.

Table 8-33// Summary of Cumulative Annual Maximum Achievable Commercial Summer MW Savings by Program

DR Program	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Critical Peak Pricing Rate with Enabling Technology	28	52	67	203	204

DR Program	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Critical Peak Pricing Rate without Enabling Technology	17	34	47	144	145
Plug-In Electric Vehicle Charging Stations Off Peak	0	0	0	2	4
Direct Load Control (DLC) Central AC Switch	2	6	13	0	0
Demand Bidding	0	0	0	2	2
Capacity Bidding	0	0	1	10	10
Base Case Total	**47**	**92**	**129**	**361**	**365**
Smart Thermostat Scenario Total	**46**	**86**	**116**	**361**	**365**

Table 8-34// Summary of Cumulative Annual Realistic Achievable Commercial Summer MW Savings by Program

DR Program	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Critical Peak Pricing Rate with Enabling Technology	1	6	20	98	99
Critical Peak Pricing Rate without Enabling Technology	0	3	11	51	51
Direct Load Control (DLC) Central AC Switch	0	2	4	3	3
Capacity Bidding	0	0	1	3	3
Base Case Total	**1**	**11**	**36**	**156**	**156**
Smart Thermostat Scenario Total	**1**	**9**	**32**	**153**	**153**

Table 8-35 and Table 8-36 show the commercial sector program MAP and RAP potential for each program for the years 2019, 2020, 2021, 2028, and 2036. The program potential is lower because it captures the effects on DR from the more efficient equipment caused by energy efficiency. Those commercial sector programs that are not listed were found to be not cost-effective, and therefore have no program potential.

Table 8-35// Summary of Cumulative Annual Program MAP Commercial Summer MW Savings by Program

DR Program	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Critical Peak Pricing Rate with Enabling Technology	27	50	63	172	166
Critical Peak Pricing Rate without Enabling Technology	17	32	44	123	118
DLC Central AC by Switch	2	6	12	0	0
Capacity Bidding	0	0	1	8	8
Demand Bidding - Base Case	0	0	0	1	1
Demand Bidding - Thermostat Scenario	0	0	0	1	1
Plug-In Electric Vehicle Charging Stations Off Peak	0	0	0	2	4
Base Case Total	**46**	**88**	**121**	**307**	**298**
Smart Thermostat Scenario Total	**44**	**83**	**109**	**307**	**298**

Table 8-36 // Summary of Cumulative Annual Program RAP Commercial Summer MW Savings by Program

DR Program	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Critical Peak Pricing Rate with Enabling Technology	1	6	19	88	86
Critical Peak Pricing Rate without Enabling Technology	0	3	11	46	45
DLC Central AC by Switch	0	2	4	3	3
Capacity Bidding	0	0	1	3	3
Demand Bidding (Thermostat Scenario Only)	1	1	1	1	1
Base Case Total	**1**	**11**	**34**	**140**	**136**
Smart Thermostat Scenario Total	**2**	**10**	**32**	**138**	**135**

8.4.3 Industrial Demand Response Potential

Table 8-37 and Table 8-38 show the MAP and RAP industrial net present values of the total benefits, costs, and savings, along with the TRC ratio for each program. MAP benefit-cost analyses are only shown for programs that had a TRC ratio of 0.95 or higher for RAP.

Table 8-37// Industrial MAP NPV Benefits, Costs, Savings, and TRC Ratios for Each Demand Response Program ($ in Millions)

Demand Response Option	NPV Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
Critical Peak Pricing Rate with Enabling Technology	$11	$1	$9	8.39
Critical Peak Pricing Rate without Enabling Technology	$39	$0	$39	80.28
Interruptible Rate	$0	$0	($0)	0
Capacity Bidding	$6	$1	$5	8.86

Table 8-38// Industrial RAP NPV Benefits, Costs, Savings, and TRC Ratios for Each Demand Response Program ($ in Millions)

Demand Response Option	NPV Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
Critical Peak Pricing Rate with Enabling Technology	$5	$1	$4	5.7
Critical Peak Pricing Rate without Enabling Technology	$11	$1	$11	21.11
Time of Use Rate with Enabling Technology	$0	$0	($0)	0
Time of Use Rate without Enabling Technology	$0	$3	($3)	0.05
Thermal Electric Storage- Cooling Rate	$0	$2	($1)	0.31
Charging of Utility Vehicles Off Peak	$3	$12	($9)	0.25
Interruptible Rate	$0	$0	$0	1.03
Capacity Bidding	$2	$1	$1	2.6
Demand Bidding	$0	$1	($1)	0.04
DLC Central AC- One-Way Switch	$0	$1	($1)	0.01
DLC AC - Smart Controllable Thermostats	$0	$1	($1)	0.01
DLC Lighting	$0	$1	($1)	0.11
DLC Room AC	$0	$1	($1)	0
DLC Electric Water Heating	$0	$1	($1)	0.03

Table 8-39 and Table 8-40 show the Program MAP and RAP residential net present values of the total benefits, costs, and savings, along with the TRC ratio for each program. Programs were only looked at for Program Potential if they were cost-effective in MAP or RAP potential.

Table 8-39// Industrial Program MAP NPV Benefits, Costs, Savings, and TRC Ratios for Each Demand Response Program ($ in Millions)

Demand Response Option	NPV Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
Critical Peak Pricing Rate with Enabling Technology	$9	$1	$8	7.24
Critical Peak Pricing Rate without Enabling Technology	$34	$0	$33	69.28
Capacity Bidding	$5	$1	$4	7.59

Table 8-40// Industrial Program RAP NPV Benefits, Costs, Savings, and TRC Ratios for Each Demand Response Program ($ in Millions)

Demand Response Option	NPV Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
Critical Peak Pricing Rate with Enabling Technology	$4	$1	$4	5.17
Critical Peak Pricing Rate without Enabling Technology	$10	$1	$10	19.13
Interruptible Rate	$0	$0	($0)	0.94
Capacity Bidding	$1	$1	$1	2.36

Table 8-41 shows the industrial sector technical, economic, achievable, and program potential.

Table 8-41// Summary of Cumulative Annual Industrial Technical, Economic, Achievable, and Program Potential – Base Case and Smart Thermostat Scenario

Potential Level	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Technical	43	65	80	207	207
Economic	25	47	63	190	190
MAP	5	10	13	39	39
RAP	0	1	3	13	13
Program MAP	5	10	12	34	32
Program RAP	0	1	3	12	11

Table 8-42 and Table 8-43 show the industrial maximum and realistic achievable potential for each program for the years 2019, 2020, 2021, 2028, and 2036. Those industrial sector programs that are not listed were found to be not cost-effective, and therefore have no achievable potential.

Table 8-42// Summary of Cumulative Annual Maximum Achievable Industrial Summer MW Savings by Program

DR Program	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)

Critical Peak Pricing Rate with Enabling Technology	1	2	3	8	7
Critical Peak Pricing Rate without Enabling Technology	4	8	10	28	28
Capacity Bidding	0	0	1	4	4
Total (Both Scenarios)	**5**	**10**	**13**	**39**	**39**

Table 8-43// Summary of Cumulative Annual Realistic Achievable Industrial Summer MW Savings by Program

DR Program	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Critical Peak Pricing Rate with Enabling Technology	0	0	1	4	4
Critical Peak Pricing Rate without Enabling Technology	0	1	2	8	8
Interruptible Rate	0.0	0.1	0.1	0.3	0.3
Capacity Bidding	0	0	0	1	1
Total (Both Scenarios)	**0**	**1**	**3**	**13**	**13**

Table 8-44 and Table 8-45 show the industrial sector program MAP and RAP potential for each program for the years 2019, 2020, 2021, 2028, and 2036. The program potential is lower because it captures the effects on DR from the more efficient equipment caused by energy efficiency Those industrial sector programs that are not listed were found to be not cost-effective, and therefore have no program potential.

Table 8-44// Summary of Cumulative Annual Program MAP Industrial Summer MW Savings by Program

DR Program	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Critical Peak Pricing Rate with Enabling Technology	1	2	2	6	6
Critical Peak Pricing Rate without Enabling Technology	4	7	9	24	22
Capacity Bidding	0	0	1	4	3
Total (Both Scenarios)	**5**	**10**	**12**	**34**	**32**

Table 8-45// Summary of Cumulative Annual Program RAP Industrial Summer MW Savings by Program

DR Program	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)

Critical Peak Pricing Rate with Enabling Technology	0	0	1	3	3
Critical Peak Pricing Rate without Enabling Technology	0	1	2	8	7
Capacity Bidding	0	0	0	1	1
Total (Both Scenarios)	**0**	**1**	**3**	**12**	**11**

8.4.4 Total Demand Response Potential

Table 8-46 and Table 8-47 show the total cost-effectiveness results for all cost-effective programs in the base case and smart thermostat scenario.

Table 8-46// Summary of DR Program Cost-Effectiveness – Base Case($ in Millions)

	NPV Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
MAP	$1,577	$622	$955	2.53
RAP	$843	$346	$497	2.43
Program MAP	$1,411	$625	$786	2.26
Program RAP	$774	$346	$428	2.24

Table 8-47// Summary of DR Program Cost-Effectiveness – Smart Thermostat Scenario ($ in Millions)

	NPV Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
MAP	MAP	$1,566	$617	$949
RAP	RAP	$698	$360	$338
Program MAP	Program MAP	$1,406	$621	$785
Program RAP	Program RAP	$642	$360	$282

Figure 8-3 and Table 8-48 show the Base Case results for technical, economic, achievable, and program potentials.

Figure 8-3// Summary of DR Program Technical, Economic, Achievable, and Program Potentials – Base Case

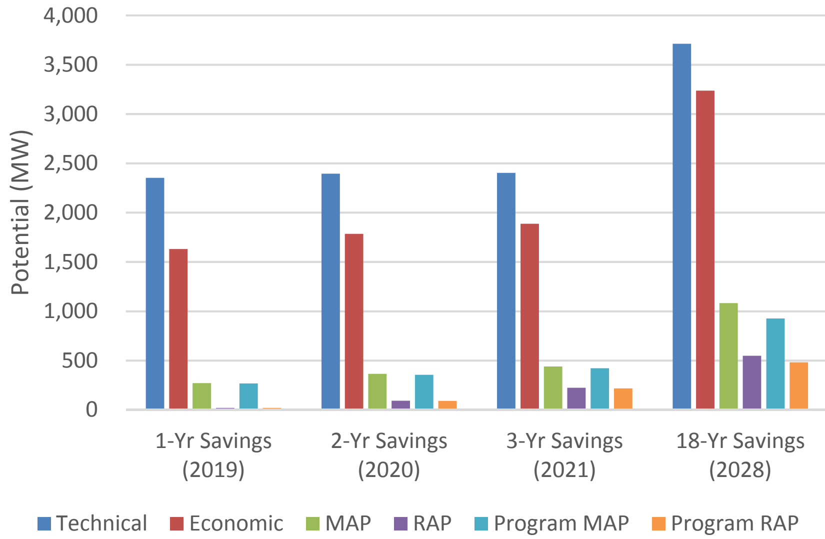


Table 8-48// Summary Cumulative Annual DR Program Technical, Economic, Achievable, and Program Potentials – Base Case

Potential Level	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Technical	2,353	2,394	2,403	3,676	3,713
Economic	1,631	1,784	1,887	3,205	3,237
MAP	272	366	440	1,064	1,082
RAP	20	93	223	537	549
Program MAP	268	355	422	947	927
Program RAP	20	92	218	492	482

Figure 8-4 and Table 8-49 show the Smart Thermostat Scenario results for technical, economic, achievable, and program potentials.

Figure 8-4// Summary of Cumulative Annual Technical, Economic, Achievable, and Program Potentials – Smart Thermostat Scenario

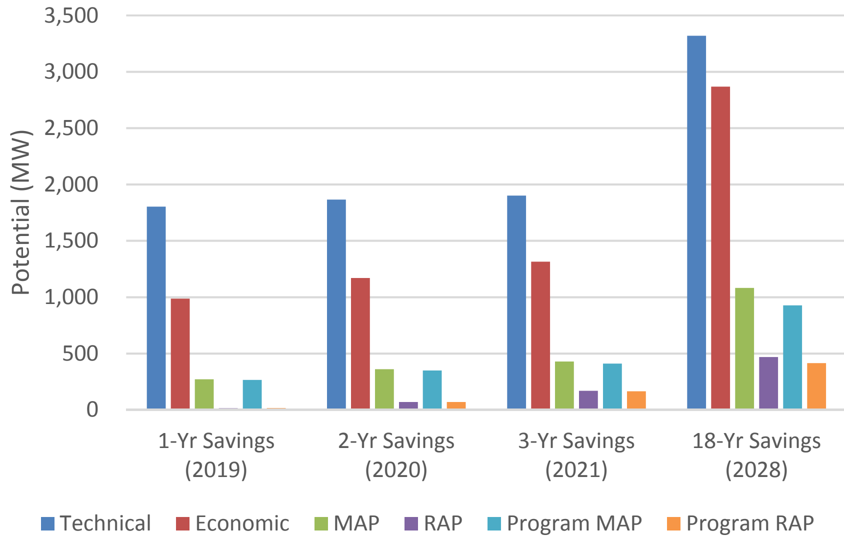


Table 8-49// Summary of Cumulative Annual DR Program Technical, Economic, Achievable, and Program Potentials – Smart Thermostat Scenario

Potential Level	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Technical	1,803	1,866	1,901	3,286	3,319
Economic	987	1,170	1,315	2,839	2,867
MAP	271	360	428	1,063	1,082
RAP	15	70	169	458	468
Program MAP	266	349	410	946	927
Program RAP	15	70	165	419	414

8.4.5 Cost of Acquiring DR Potential

Table 8-50 through Table 8-53 show the Program MAP and RAP program costs for the Base Case and Smart Thermostat Scenario. Non-equipment incentives are included in these budgets.

Table 8-50// Summary of DR Program MAP Budget Requirements – Base Case

	Residential Achievable Potential Cost	Commercial Achievable Potential Cost	Industrial Achievable Potential Cost	Total Achievable Potential Cost
2019	$32,836,546	$10,751,047	$383,560	$43,971,153
2020	$32,376,522	$10,062,891	$172,082	$42,611,495
2021	$31,560,801	$8,335,253	$190,006	$40,086,059
2022	$33,459,463	$7,790,772	$238,086	$41,488,321
2023	$36,720,974	$8,821,081	$278,358	$45,820,413
2024	$39,827,077	$10,153,708	$306,129	$50,286,914
2025	$42,178,152	$10,320,381	$331,863	$52,830,396
2026	$44,641,293	$10,724,071	$354,470	$55,719,834
2027	$47,043,457	$11,104,753	$379,010	$58,527,220

	Residential Achievable Potential Cost	Commercial Achievable Potential Cost	Industrial Achievable Potential Cost	Total Achievable Potential Cost
2028	$49,978,472	$11,611,875	$401,709	$61,992,057
2029	$53,841,900	$15,134,069	$433,642	$69,409,611
2030	$53,563,955	$14,495,890	$410,532	$68,470,377
2031	$51,048,790	$11,610,928	$383,816	$63,043,535
2032	$51,359,753	$10,518,909	$382,020	$62,260,683
2033	$53,701,113	$11,584,157	$393,243	$65,678,513
2034	$55,867,957	$13,013,060	$405,386	$69,286,402
2035	$57,054,489	$13,000,561	$411,092	$70,466,143
2036	$58,302,756	$13,260,586	$414,243	$71,977,585

Table 8-51// Summary of DR Program MAP Budget Requirements – Smart Thermostat Scenario

	Residential Achievable Potential Cost	Commercial Achievable Potential Cost	Industrial Achievable Potential Cost	Total Achievable Potential Cost
2019	$32,836,546	$10,242,819	$383,560	$43,462,926
2020	$32,376,522	$8,832,265	$172,082	$41,380,869
2021	$31,560,801	$6,397,668	$190,006	$38,148,475
2022	$33,459,463	$6,685,232	$238,086	$40,382,780
2023	$36,720,974	$8,257,950	$278,358	$45,257,282
2024	$39,827,077	$9,674,251	$306,129	$49,807,457
2025	$42,178,152	$9,938,713	$331,863	$52,448,727
2026	$44,641,293	$10,440,745	$354,470	$55,436,508
2027	$47,043,457	$10,919,916	$379,010	$58,342,383
2028	$49,978,472	$11,525,671	$401,709	$61,905,852
2029	$53,841,900	$14,712,924	$433,642	$68,988,466
2030	$53,563,955	$13,487,924	$410,532	$67,462,411
2031	$51,048,790	$10,118,577	$383,816	$61,551,184
2032	$51,359,753	$9,927,848	$382,020	$61,669,622
2033	$53,701,113	$11,505,099	$393,243	$65,599,455
2034	$55,867,957	$12,932,563	$405,386	$69,205,906
2035	$57,054,489	$12,918,711	$411,092	$70,384,292
2036	$58,302,756	$13,177,304	$414,243	$71,894,304

Table 8-52// Summary of DR Program RAP Budget Requirements – Base Case

	Residential Achievable Potential Cost	Commercial Achievable Potential Cost	Industrial Achievable Potential Cost	Total Achievable Potential Cost
2019	$7,403,056	$1,208,910	$385,882	$8,997,848
2020	$24,491,488	$2,381,692	$159,140	$27,032,319

	Residential Achievable Potential Cost	Commercial Achievable Potential Cost	Industrial Achievable Potential Cost	Total Achievable Potential Cost
2021	$45,796,925	$6,270,512	$204,958	$52,272,395
2022	$35,831,058	$6,867,987	$221,786	$42,920,831
2023	$24,760,963	$5,801,035	$223,027	$30,785,025
2024	$21,542,652	$4,978,541	$225,826	$26,747,019
2025	$22,419,206	$5,069,199	$237,764	$27,726,169
2026	$23,350,082	$5,287,464	$248,574	$28,886,121
2027	$24,261,338	$5,511,717	$259,693	$30,032,749
2028	$25,406,351	$5,743,362	$271,268	$31,420,981
2029	$15,723,093	$2,052,846	$253,335	$18,029,274
2030	$31,122,542	$4,030,110	$256,948	$35,409,600
2031	$49,618,655	$8,141,812	$288,552	$58,049,020
2032	$40,102,270	$8,624,773	$295,496	$49,022,538
2033	$29,614,346	$7,276,526	$288,626	$37,179,499
2034	$26,077,095	$6,220,510	$284,169	$32,581,775
2035	$26,613,851	$6,205,010	$289,199	$33,108,060
2036	$27,176,498	$6,329,437	$293,244	$33,799,178

Table 8-53 // Summary of DR Program RAP Budget Requirements – Smart Thermostat Scenario

	Residential Achievable Potential Cost	Commercial Achievable Potential Cost	Industrial Achievable Potential Cost	Total Achievable Potential Cost
2019	$2,594,079	$1,157,695	$385,882	$4,137,656
2020	$10,063,524	$2,046,736	$159,140	$12,269,400
2021	$25,349,323	$5,714,916	$204,958	$31,269,196
2022	$26,236,941	$6,516,065	$221,786	$32,974,792
2023	$21,272,746	$5,625,189	$223,027	$27,120,962
2024	$18,199,772	$4,871,396	$225,826	$23,296,994
2025	$19,222,581	$4,982,143	$237,764	$24,442,489
2026	$20,300,011	$5,215,413	$248,574	$25,763,999
2027	$21,358,114	$5,454,592	$259,693	$27,072,399
2028	$22,650,266	$5,701,127	$271,268	$28,622,661
2029	$8,549,906	$1,872,599	$253,335	$10,675,839
2030	$15,076,962	$3,661,479	$256,948	$18,995,389
2031	$28,850,979	$7,609,185	$288,552	$36,748,716
2032	$30,998,706	$8,327,648	$295,496	$39,621,850
2033	$26,782,787	$7,157,709	$288,626	$34,229,122
2034	$23,238,589	$6,166,398	$284,169	$29,689,156
2035	$23,768,231	$6,157,841	$289,199	$30,215,271
2036	$24,323,681	$6,282,879	$293,244	$30,899,803

8.5 COMPARISON TO PRIOR STUDY IN 2013

The demand response potential realized in the 2016 study is much higher than in the 2013 study. There are several reasons for this. GDS assumes opt-out rates for MAP, where the 2013 study assumed opt-in rates for MAP. GDS included rate programs for RAP, where the 2013 study did not. The 2016 study also considered a much more comprehensive list of programs than the 2013 study. Figure 8-5 and Figure 8-6 show the results in the 2013 and 2016 studies for years 1, 2, 3, 10, and 18.

Figure 8-5// Comparison of Cumulative Annual Maximum Achievable DR Potential in 2013 Study to 2016 Study

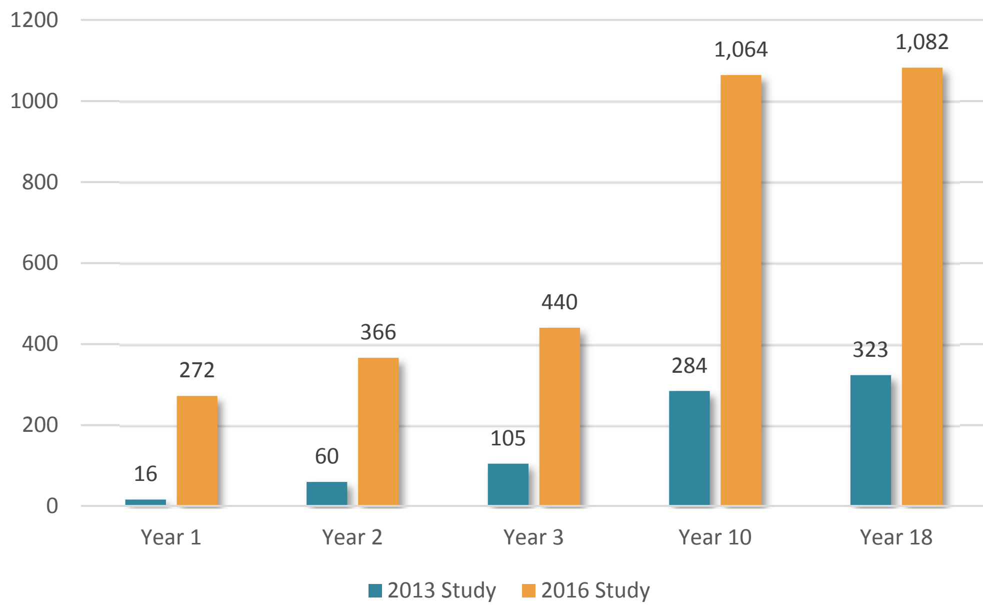
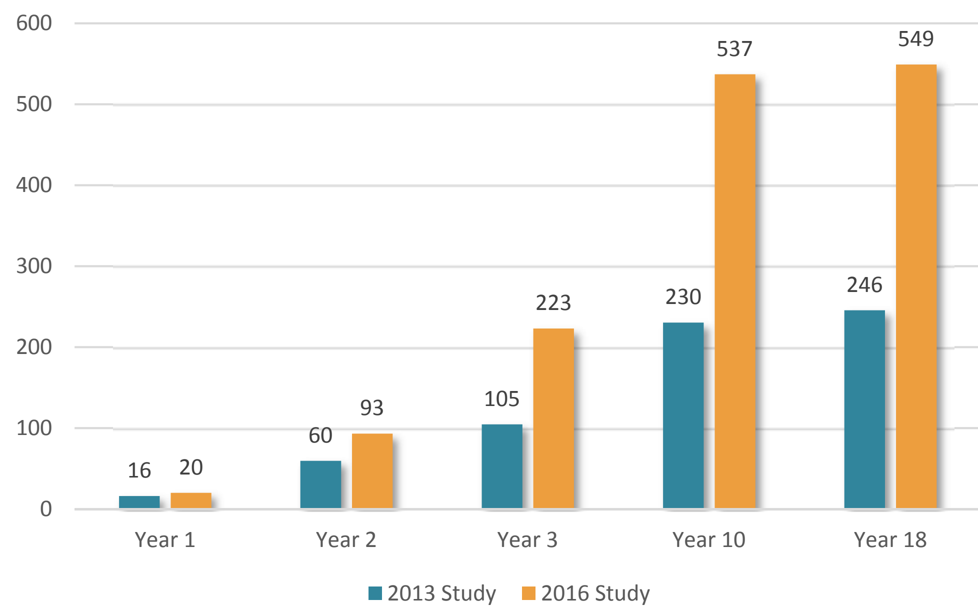


Figure 8-6// Comparison of Cumulative Annual Realistic Achievable DR Potential in 2013 Study to 2016 Study



9 DISTRIBUTED GENERATION/COMBINED HEAT & POWER POTENTIAL[91]

9.1 INTRODUCTION

This analysis of Combined Heat & Power (CHP) and Rooftop Solar Photovoltaics (RSPV) as Distributed Generation (DG) potential provides a roadmap for both policy makers and Ameren Missouri as they develop strategies and programs for increasing the amount of cost-effective CHP and RSPV resources in the Ameren Missouri service area. Specifically, this section of the report identifies a set of potential options and presents an analysis of the costs, benefits and resource potential for CHP/DG and RSPV/DG. CHP systems generate electric power and useful thermal energy in a single, integrated system. Heat that is normally wasted in conventional power generation is recovered as useful thermal energy. Due to the integration of both power and thermal generation, CHP systems are more efficient than separate sources for electric power generation and thermal energy production. This provides environmental, economic, and energy system infrastructure benefits. DG refers to power generation at the point of consumption. RSPV technology was analyzed in this potential study. RSPV is a system that uses solar panels mounted on a rooftop of a home or business to generate electricity.

The direct benefits of CHP for facility operators can be:

- **Reduced Energy Related Costs** – providing direct cost savings.
- **Increased Reliability and Decreased Risk of Power Outages** due to the addition of a separate power supply.
- **Increased Economic Competitiveness** due to lower cost of operations.

In addition to these direct benefits, the electric industry, electricity customers, and society, in general, derive benefits from RSVP and CHP deployment, including:

- **Increased Energy Efficiency** – Combined heat and power equipment is much more efficient than central station power generation.
- **Economic Development Value** – allowing an option for businesses to be more economically competitive on a global market thereby maintaining local employment and economic health.
- **Reduction in Emissions that Contribute to Global Warming** – increased efficiency of energy use allows facilities to achieve the same levels of output or business activity with lower levels of fossil fuel combustion and reduced emissions of carbon dioxide.
- **Reduced Emissions of Criteria Air Pollutants** – CHP systems can reduce air emissions of carbon monoxide (CO), nitrogen oxides (NOx), and sulfur dioxide (SO2) especially when state-of-the-art CHP equipment replaces outdated and inefficient boilers at the site.
- **Increased Reliability and Grid Support** for the utility system and customers as a whole.
- **Resource Adequacy** – reduced need for regional power plant and transmission and distribution infrastructure construction.

9.1.1 Study Scope

The GDS analysis of CHP potential in the Ameren Missouri territory over the 18-year study period considered both traditional "topping cycle" and "bottoming cycle" or waste heat to power CHP. This is consistent with that latest U.S. Department of Energy's Report on Combined Heat and Power Potential in the United States. Topping cycle CHP systems are the most common CHP systems currently in use. In a topping cycle system, fuel is first combusted to generate electricity. A portion of the heat left over from the electricity generation process is then converted into useful thermal energy (e.g. heating, hot water, or steam for industrial processes). A bottoming-cycle CHP system, uses the reverse process. Fuel

[91] EO-2017-0073 1.A(3)

is first combusted to provide thermal input to industrial process equipment like a kiln or furnace, and the heat rejected from the process is then captured and used for power production. [92] CHP technologies include:

- Reciprocating Engines
- Combustion Turbines
- Boiler/Steam turbines
- Combined Cycles

Applications with steady demand for electricity and thermal energy are potentially good economic targets for CHP deployment. Industrial applications, particularly in industries with continuous processing and high steam requirements, are very economic and represent a large share of existing CHP capacity today. Commercial applications such as hospitals, nursing homes, laundries, and hotels with large hot water needs are well suited for CHP. Institutional applications such as colleges and schools, prisons, and residential and recreational facilities are also excellent prospects for CHP.

Another type of on-site or DG system that was considered in this analysis is rooftop solar PV systems (RSPV) that use solar energy to generate electricity. Typically, RSPV generation offsets only a portion of baseline loads, and, in most cases, is considered a secondary source for a building's energy needs. RSPV electrical generation above the building's load feeds into the electric grid. The amount of such excess generation greatly depends on the RSPV system's size and for residential customers, it often occurs when homes are unoccupied.

GDS produced the following estimates of CHP potential which are summarized below. A more detailed discussion of how CHP Potential estimates were developed for each type of potential can be found in Section 9.3.1.

Technical Potential | All technically feasible potential is included to provide a measure of the theoretical maximum CHP potential.

Economic Potential | All CHP options included in technical potential are screened for cost-effectiveness by comparing the anticipated benefits and costs as defined by the Total Resource Cost (TRC) Test. Only cost-effective CHP options are included in the economic potential.

Maximum Achievable Potential (MAP) | This is the maximum cost-effective CHP potential that can practically be attained in a real-world program delivery scenario, assuming that incentives and take rates are at the high end of actual utility program offerings and results.

Realistically Achievable Potential (RAP) | This represents an estimate of the amount of CHP potential that can realistically be achieved given typical industry experience with similar CHP program offerings.

Maximum Achievable Program Potential (MAPP) | This is the maximum cost-effective CHP potential that can practically be attained, with adjustments for potential free riders or utility budgets that may be less than what is necessary achieve the full maximum potential.

Realistically Achievable Program Potential (RAPP) | This represents an estimate of the amount of CHP program potential that can realistically be achieved with program budgets that are representative of expected utility funding levels or the targeting at smaller CHP systems.

[92] U.S. Department of Energy, Combined Heat and Power (CHP) Technical Potential in the United States, March 2016, p. ii.

To address the issue of uncertainty around CHP potential estimates, GDS conducted sensitivity analysis for the following scenarios:

***Avoided Cost Scenario**:* This scenario considered the impact of higher and lower avoided costs.

- The high avoided cost scenario assumed 30% higher avoided cost plus gas benefits that are 7.5% greater that the base case. This includes an estimate for non-energy benefits.[93]
- The low avoided cost scenario assumed that avoided costs are 50% lower than the base case, with no gas benefits

***Take Rate Scenario**:* This scenario considered the impacts of take rate lift and drag factors on CHP potential.

9.2 CHARACTERIZATION OF CHP IN THE AMEREN MISSOURI SERVICE AREA

There are only 4 existing operable CHP sites within the Ameren Missouri service area, representing a total installed capacity of 57.3 MW.[94] CHP is generally dependent on natural gas availability, including pipeline capacity availability, and customer steam usage. Ameren Missouri assumes almost all electric customers also have access to natural gas either via the distribution system or the wholesale pipeline system.

Ameren Missouri does not currently have predetermined financial incentives for CHP projects. However, the Stipulation & Agreement (between Ameren Missouri, Missouri Public Service Commission, OPC, NHT, NRDC, Renew Missouri, Tower Grove, and Missouri Department of Economic Development – Division of Energy) allows Ameren Missouri to consider CHP projects submitted by business customers under the current Business Custom program. If a CHP project was submitted for consideration to receive an incentive via the Business Custom program, Ameren Missouri would then determine an appropriate incentive.

Regarding RSPV, data provided by Ameren shows that the Company currently has 3844 solar customers representing a total of 55.1 MW of installed capacity. An independent estimate developed by GDS based on statewide data put the total at 56 MW of installed capacity. To research existing solar installations in the Ameren service territory, GDS utilized multiple sources including database research through the Missouri Solar Energy Industries Association, NREL OpenPV project database and direct correspondence with Ameren engineers. Our final installed project estimate totals 56 MW of installed capacity and is an aggregate of the aforementioned database searches and includes a reduction of non-applicable solar installations including solar farms and other ground mounted installations.

Rooftops provide a large expanse of untapped area for solar energy generation, and onsite distributed generation could potentially reduce the costs and losses associated with the transmission and distribution of electricity. However, rooftop suitability is a significant issue impacting current and future RSPV installations along with other issues such as grid flexibility, supporting infrastructure, and enabling technologies.

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93 At the time this document was prepared non-energy benefits and natural gas benefits are not included in the scope of benefits under MEEIA. However, because the topic of non-energy benefits and joint electric/natural gas programs has been discussed in various regulatory forums, the Company felt it was appropriate to evaluate a sensitivity where those factors were included.

94 U.S. DOE Combined Heat and Power Installation Database, https://doe.icfwebservices.com/chpdb/state/MO and discussions with Ameren Missouri.

9.3 METHODOLOGY

This section describes the methodology and data sources used by GDS to determine the potential for CHP and RSPV.

9.3.1 CHP Potential Methodology

For CHP the step by step analytical process and relevant data sources used to develop technical, economic, achievable and program potential estimates are as follows:

1) **Technical Potential**: GDS applied the methodology used by the U.S. DOE as described in its latest National CHP Potential Study. [95] In general, that approach consisted of the following elements:
   - Identify target markets where CHP provides a reasonable fit to the electric and thermal needs of the user. Target applications are identified based on reviewing the electric and thermal energy consumption data for various building types and industrial facilities.
   - Quantify the number and size distribution of target markets. Several data sources were used to identify the number of target candidate facilities in each target application that meet the electric and thermal load requirements for CHP.
   - Estimate CHP potential in terms of MW electric capacity. CHP potential is derived based on the thermal and electric load for each site. Total CHP potential for each target market is then calculated by the amount of CHP potential in each size category.
   - Subtract existing CHP from the identified sites to determine the remaining technical potential.
2) Collected billing kWh and kW demand data for the latest 12 months (12 months ending August or September 2016) for 157,000 Ameren Missouri C/I customers.
3) Selected customers from North American Industry Classification System (NAICS) market segments where CHP is suitable (where there is a thermal load).
4) Obtained equipment and facility power to heat ratios from the DOE National CHP Potential Study referenced in Step 1. Used this data to calculate CHP kW and kWh potential for each customer where CHP is suitable and developed a total CHP technical potential estimate.
5) **Economic Potential:** Determined that 72% of the individual CHP measures were cost-effective based on measure level cost-effectiveness for various types and sizes of CHP equipment. The CHP technical potential was then multiplied by this 72% factor to get an estimate of economic potential. This is an initial factor that can be adjusted once Ameren Missouri gains more experience with a CHP program. It is important to note that the benefit/cost analysis of CHP equipment takes into account the higher efficiency of CHP systems in addition to the avoided costs of electric generation capacity, generation energy and T&D avoided costs. Thus the benefit/cost analysis for CHP equipment is substantially different than for energy efficiency or demand response resources.
6) **Maximum Achievable Potential (MAP):** GDS used the data from a recent ComEd CHP Potential Study[96] that found that 20% of economic potential is achievable over the long run and the 20% factor was used to calculate MAP at the measure level in 2036.
7) **Realistic Achievable Potential (RAP):** RAP is assumed to be 10% lower than the measure level MAP in each year of the study period. The 10% factor is based on an analysis of regional and national CHP evaluations, notably the ComEd CHP Potential Study referenced in step 6. This study showed 427 MW of MAP and 380 MW of RAP.[97]

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[95] U.S. Department of Energy, Combined Heat and Power (CHP) Technical Potential in the United States, Appendix A, March 2016, p. A-1.

[96] ICF International, Assessment of the Technical and Economic Potential for CHP in Commonwealth Edison's Service Territory, May 2016, p. 17.

[97] ICF International, Assessment of the Technical and Economic Potential for CHP in Commonwealth Edison's Service Territory, May 2016, pp. 15, 18.

8) **Program Potential – MAP (Program MAP):** Because the market analysis for CHP equipment is different than for energy efficiency or demand response measures, GDS developed a unique modeling approach for CHP program potential. It is assumed that 85% of the measure level MAP can be achieved through a CHP Program. This allows for the exclusion of large projects 5 MW's and over as these projects are likely to be free-riders.[98]

9) **Program Potential – RAP (Program RAP):** Program-RAP represents a reduction from Program-MAP based on allocating the expected program budget to smaller kW projects.

9.3.2 Rooftop Solar PV (RSPV) Potential Methodology

For RSPV the step by step analytical process and relevant data sources used to develop technical, economic, achievable and program potential estimates are as follows:

1) **Technical Potential:** The analysis started with an estimate of the RSPV technical potential for Missouri of 28.3 GW from the NREL January 2016 Rooftop Solar PV Study.[99] This number was then adjusted to account for the Ameren peak period and the coincident peak demand savings of solar during that summer peak period using a coincidence factor of 26%.[100]

2) The estimate of RSPV technical potential for the state of Missouri was multiplied by 40% to adjust down the technical potential estimate to the Ameren Missouri service area. Ameren has 40% of Missouri residential, commercial and industrial electric customers in the state of Missouri.

3) **Economic Potential:** RSPV equipment of various kW sizes (6 kW, 100kW, 1000 kW) all passed the TRC test screening. All of the projections of the installed cost per watt for rooftop solar PV were based on detailed projections and reports obtained from the National Renewable Energy Laboratory (NREL). Because all of the rooftop solar PV systems analyzed for this study passed TRC screening, it was assumed that all technical potential for this equipment is economic.

4) **Maximum Achievable Potential (MAP):** A 30% factor was applied to economic potential to calculate MAP in 2036. The 2016 NREL Standard Scenario Analyses found that MAP is 30% of economic potential.[101] Thus the GDS estimate for the maximum achievable potential for rooftop solar PV in the Ameren Missouri service area is based on recent NREL projections.

5) **Realistic Achievable Potential (RAP)**: A 14% factor was applied to economic potential to calculate RAP in 2036. The 14% is based on take rate research conducted by EMI as part of this study. It represents the most conservative take rates for commercial and industrial measures to reflect the very long payback of RSPV equipment (estimated at over 15 years, currently).

6) **Program Potential – MAP (Program MAP):** Program-MAP is based on a program budget assumption of $10 million a year, starting in 2019, escalated by general inflation. GDS selected a budget of $10 million a year in order to allow Ameren Missouri to provide financial incentives to several thousand customers for the purchase of rooftop solar PV equipment.

7) **Program Potential – RAP (Program RAP):** Program-RAP is based on a program budget of $5 million a year, starting in 2019, escalated by general inflation. The lower budget for realistically achievable program potential will allow Ameren Missouri to provide incentives to a smaller number of customers than in the program potential MAP scenario.

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[98] ICF International, Assessment of the Technical and Economic Potential for CHP in Commonwealth Edison's Service Territory, May 2016, p. 15.
[99] NREL, Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment, p. 35.
[100] GDS performed a PVWatts model based upon a rooftop solar PV installation in the Ameren Missouri service area and analyzed the peak coincidence factor.
[101] NREL, 2016 Standard Scenarios Report: A U.S. Electricity Sector Outlook, November 2016, p. ix.

9.3.3 Economic Analysis Assumptions

The electric avoided costs used to determine utility benefits were provided by Ameren Missouri. Avoided electric generation capacity refers to the CHP program benefits resulting from a reduction in system energy requirements and the need for new generation capacity. CHP programs can also potentially delay the construction of new transmission and distribution lines and facilities, which is reflected in avoided T&D costs.

The discount rate used in this study is 5.8%. A peak demand line loss factor of 5.72% for residential and 4.84% for commercial and industrial sectors, and a reserve margin of 17 % (for firm load reduction) were also applied to demand reductions at the customer meter. These values were provided by Ameren Missouri.

Table 9-1 shows the cost, useful life and operating assumptions used to determine the cost-effectiveness of CHP and RSPV measures.

Table 9-1 / / CHP and RSPV Cost, Useful Life and Operating Assumptions

Measure Type	Life	Size (kW)	Total Installed Cost	O&M Fixed Cost ($/Yr/kW)	O&M Variable Cost ($/kWh)	Capacity Factor	Fuel Type
Reciprocating Engine	20 Years	100	$290,000	$ -	$.023-.025	80%	Diesel, Natural Gas, Biogas (For 1000 kW engine operating on biogas, added equipment & install cost is $600/kW), Hydrogen, Propane.
		633	$1,795,821	$ -	$0.0210		
		1121	$2,652,286	$ -	$0.0190		
		3326	$5,990,126	$ -	$0.0160		
		9341	$13,385,653	$ -	$0.0085		
Combustion Turbine	20 Years	3304	$10,840,424	$ -	$0.0126	80-95%	Natural Gas, Hydrogen, Propane.
		7038	$14,639,040	$ -	$0.0123		
		9950	$19,661,200	$ -	$0.0120		
		20336	$30,870,048	$ -	$0.0093		
		44488	$55,521,024	$ -	$0.0092		
Steam Turbine	20 Years	500	$568,000	$ 0.0100	Typically below $.01/kWh	85-95%	Natural Gas, Biomass, Hydrogen, Propane.
		3000	$2,046,000	$ 0.0090			
		15000	$9,990,000	$ 0.0060			
Microturbines	20 Years	30	$129,000	$ -	$ 0.0200	85-90%	Natural Gas, Biogas, Hydrogen, Propane.
		65	$209,300	$ -	$ 0.0130		

Measure Type	Life	Size (kW)	Total Installed Cost	O&M Fixed Cost ($/Yr/kW)	O&M Variable Cost ($/kWh)	Capacity Factor	Fuel Type
		200	$630,000	$ -	$ 0.0160		
		250	$687,500	$ 9.1200	$ 0.0100		
		333	$859,140	$ 6.8470	$ 0.0070		
		1000	$2,500,000	$ -	$ 0.0120		
Fuel Cells	20 Years	0.7	$15,400	$ -	$ 0.0600	80-98%	Natural Gas, Biogas, Hydrogen, Propane.
		1.5	$34,500	$ -	$ 0.0550		
		300	$3,000,000	$ -	$ 0.0450		
		400	$2,800,000	$ -	$ 0.0360		
		1400	$6,440,000	$ -	$ 0.0400		
Organic Rankine Cycle	15 years	500	$1,800,000.00	$ -	$ 0.9940	80%	Waste heat (steam)
RSPV	33 years (Source: February 2016 National Renewable Energy Lab Study)	6[102]	$14,249	$ 21.00	$ -	15%	N/A
		100	$147,256	$ 19.00	$ -		
		1000	$997,495	$ 16.00	$ -		

Source data for each of the above CHP and RSPV assumptions can be found in the appendices of this report.

9.4 TECHNICAL, ECONOMIC, ACHIEVABLE, PROGRAM POTENTIAL RESULTS

This section of the report presents the Technical, Economic, Achievable (MAP and RAP) and Program Potential (Program-MAP and Program MAP) for CHP and RSPV. It also presents the annual budget that will be required to acquire the identified program potential, and the net present value of program benefits and costs.

9.4.1 Combined Heat & Power Distributed Generation Potential

Table 9-2 shows all of the CHP cumulative annual potential estimates for the years 1 to 3 and years 10 and 18 of the study period.

[102] All of the installed costs per watt for rooftop solar PV are based upon data and projections obtained from the National Renewable Energy Laboratory and the Lawrence Berkeley National Laboratory.

Table 9-2 / / CHP – Cumulative Annual Technical, Economic, Achievable and Program Potential

Year	Technical (MW)	Economic (MW)	MAP (MW)	RAP (MW)	PP-MAP (MW)	PP-RAP (MW)
2019	436.1	311.7	3.8	3.4	3.2	2.9
2020	439.2	312.7	7.6	6.8	6.4	5.8
2021	440.1	314.0	11.3	10.2	9.7	8.7
2028	459.4	325.9	37.8	34.0	32.2	28.9
2036	478.3	342.8	68.1	61.3	57.9	52.1

The significant difference between economic potential and MAP/RAP reflects the anticipated customer acceptance of CHP investments at different payback levels. For example, a recent customer survey conducted as part of a Commonwealth Edison CHP potential study[103] found that more than 30 percent of customers surveyed would reject a project that promised to return their initial investment in just 1 year. For most of the customer types, a little more than half would reject a project with a payback of 2 years. This type of payback translates into a project with a return on investment of around 50 percent. Potential explanations for rejecting a project with such high returns include:

- The average customer does not believe that the results are valid and is attempting to mitigate this perceived risk by requiring very high projected returns before a project would be accepted.
- The facility has limited capital and is rationing its ability to raise capital for higher-priority projects (market expansion, product improvement, etc.).

9.4.2 Rooftop Solar PV Distributed Generation Potential

Table 9-3 shows all of the RSPV potential estimates for the years 1-3 and years 10 and 18 of the study period for demand savings potential during the Ameren peak using the coincidence factors derived from PVWatts modeling. The generating capacity is shown as demand savings.

Table 9-3 / / RSPV – Cumulative Annual Technical, Economic, Achievable and Program Potential Demand Savings
(Available at the Time of the Ameren Missouri Summer Peak)

Year	Technical (MW)	Economic (MW)	MAP (MW)	RAP (MW)	Program-MAP (MW)	Program-RAP (MW)
2019	2,251.0	2,251.0	38.0	18.0	0.0	0.0
2020	2,251.0	2,251.0	75.0	35.0	0.0	0.0
2021	2,251.0	2,251.0	113.0	53.0	7.4	3.7
2028	2,251.0	2,251.0	375.0	175.0	59.1	29.6
2036	2,251.0	2,251.0	675.0	315.0	118.3	59.1

All of the various sizes of RSPV equipment included in technical potential were found to be cost-effective (TRC test value of greater than 1.0). Therefore, all of the technical potential was assumed to be economic. The significant difference between economic potential and MAP/RAP reflects the fact that according to the National Renewable Energy Lab, the future of rooftop PV is heavily dependent on the evolution of retail electricity rate structures, system costs, net metering, and other policies supporting adoption, many of which are currently being reconsidered.[104]

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[103] ICF International, Assessment of the Technical and Economic Potential for CHP in Commonwealth Edison's Service Territory, May 2016, p. 13.
[104] NREL, 2016 Standard Scenarios Report: A U.S. Electricity Sector Outlook, November 2016, p. ix.

No RSPV program potential is shown for 2019 and 2020 as there is not expected to be funding for RSPV programs until 2021.

9.4.3 Program Budgets

Annual program budgets for CHP and RSPV Shown in Table 9-4.

Table 9-4 / /CHP Program MAP & RAP Budgets ($ in Millions)

Year	CHP Program MAP Budget (Millions)	CHP Program RAP Budget (Millions)	RSPV Program MAP Budget (Millions)	RSPV Program RAP Budget (Millions)
2019	$9.1	$8.4	$0.0	$0.0
2020	$9.1	$8.4	$0.0	$0.0
2021	$9.1	$8.4	$10.0	$5.0
2022 – 2036	$9.1	$8.4	$10.0	$5.0

Program budgets reflect the following assumptions regarding CHP and RSPV:

- The RSPV assumed incentive is $.25/installed watt for systems up to 25kW, as comparable programs are not incentivizing larger systems. This RSPV incentive starts in 2021.
- For CHP, there is an assumed installation incentive of $200/kw up to $25,000 (or 50% of installed cost) and a performance rebate of $.07/kWh, paid until a project hits a $2 million total rebate.
- Program administrative cost of 8% of the total incentive costs was assumed for both CHP and RSPV.

The above assumptions are based on a review of other utility CHP and RSPV programs. The primary source of this data was the Database of State Incentives for Renewables and Efficiency (DSIRE database).[105]

9.4.4 Program Cost-Effectiveness

Table 9- shows the net present values (NPV) of the total benefits, costs, and savings, along with the TRC ratios for the CHP and the RSPV programs (Program-MAP and Program-RAP).

Table 9-6 / /Program MAP & RAP NPV of Benefits/Costs and TRC Ratio ($ in Millions)

Potential Type	NPV Lifetime TRC Benefits	NPV TRC Costs	NPV TRC Net Benefits	18-YR TRC Ratio
Program-MAP				
CHP	$1,535.2	$1,215.2	$319.9	1.3
RSVP	$902.0	$571.2	$330.8	1.6
Program-RAP				
CHP	$1,432.0	$1,132.0	$299.9	1.3
RSVP	$451.0	$285.6	$165.4	1.6

105 DSIRE is the most comprehensive source of information on incentives and policies that support renewables and energy efficiency in the United States. Established in 1995, DSIRE is operated by the N.C. Clean Energy Technology Center at N.C. State University and is funded by the U.S. Department of Energy: http://www.dsireusa.org/

The NPV benefits and costs show a positive, and similar, TRC ratio for both Program-MAP and Program-RAP scenarios with a slight increase in the TRC for RSVP in program RAP case as the costs reduce substantially but benefits remain high.

9.5 COMPARISON TO PRIOR STUDY IN 2013

Ameren Missouri conducted a similar CHP and DG potential study in 2013. The results of this study and the prior 2013 study are compared in Table 9-. The DG MW savings potential is shown as demand savings. Because GDS was not provided with the CHP/DG program potential results, there is no comparison in this report of the 2016 study program MAP and RAP savings potential results for CHP/DG to the 2013 study results.

Table 9-7//Comparison of 2016 Study Cumulative Annual DR Program MW Savings Potential to 2013 Study

Year	Technical (MW)	Economic (MW)	Max Achievable (MW)	Realistic Achievable (MW)
2013 Study - CHP				
1	58.0	6.5	1.0	1.0
2	723	8.2	1.2	1.0
3	90.2	10.3	1.5	1.0
10	384.4	44.4	6.9	4.9
18	1,291.7	241.4	51.7	37.8
2016 Study - CHP				
1	436.1	311.7	3.8	3.4
2	439.2	312.7	7.6	6.8
3	440.1	314.0	11.3	10.2
10	459.4	325.9	37.8	34.0
18	478.3	342.8	68.1	61.3
2013 Study - RSPV				
1	65.9	0.0	0.0	0.0
2	82.0	0.0	0.0	0.0
3	101.8	0.0	0.0	0.0
10	418.9	0.0	0.0	0.0
18	1,390.8	1,390.8	218.0	160.0
2016 Study – RSPV (Demand Savings)				
1	2,251.0	2,251.0	38.0	18.0
2	2,251.0	2,251.0	75.0	35.0
3	2,251.0	2,251.0	113.0	53.0
10	2,251.0	2,251.0	375.0	175.0
18	2,251.0	2,251.0	675.0	315.0

10 COMBINED RESULTS

This section provides the total cost-effectiveness, savings, and program budgets for each study, along with a combined total. The Behavioral, DR, and DG/CHP studies are all affected by the Energy Efficiency study and take those efficiency gains into account. DR and DG/CHP studies are also affected by the Behavioral study.

10.1.1 Cumulative Annual Potential Savings

Table 10-1 shows the combined Program MAP and Program RAP MWh potential. Note that interactions across studies are not accounted for until program potential is calculated, thus only Program MAP and Program RAP are shown as combined totals. These values include the Energy Efficiency, Behavior, and Distributed Generation/ Combined Heat and Power studies. Figure 10-1 shows the potential energy savings, as a percent of forecast electricity sales, broken out by EE, Behavior and DG/CHP. There are no expected energy (MWh) savings from DR programs.

Table 10-1// Cumulative Annual MWh Savings – EE, Behavior, & DG/CHP Combined

Energy (MWh)	2019 Potential (MWh)	2020 Potential (MWh)	2021 Potential (MWh)	2028 Potential (MWh)	2036 Potential (MWh)
Program MAP	849,674	1,520,765	2,060,622	5,914,449	8,714,448
Program RAP	303,770	641,254	1,324,446	4,479,497	6,846,568

Figure 10-1// 2036 Cumulative Annual MWh Savings as % of Base Forecast Sales – All Studies Combined

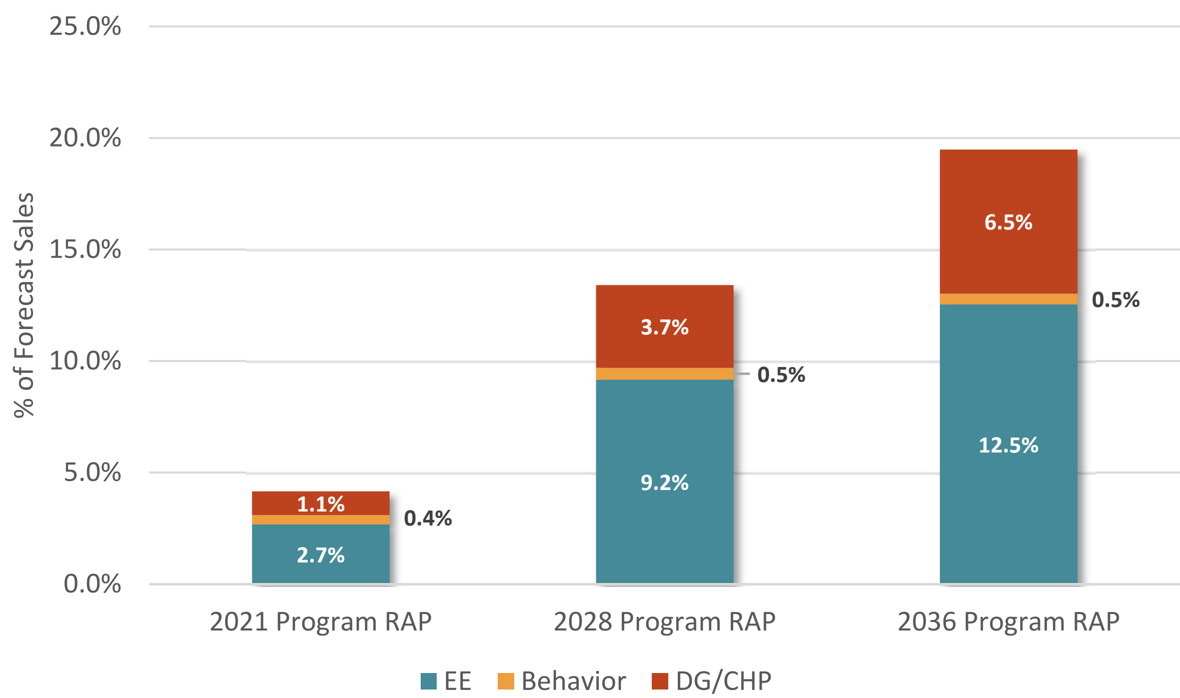
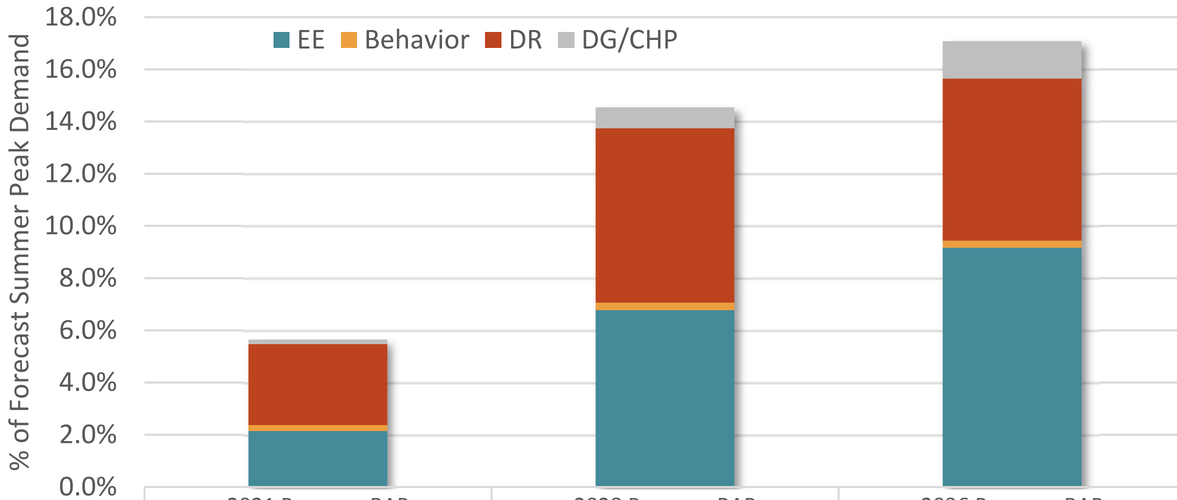


Table 10-2 shows the combined Program MAP and Program RAP MW potential. Figure 10-2 shows the potential MW savings, as a percent of summer peak demand, broken out by EE, Behavior and DG/CHP. These values include all four studies: Energy Efficiency, Behavior, Demand Response, and Distributed Generation/ Combined Heat and Power.

Table 10-2// Cumulative Annual MW Savings – EE, Behavior, DR & DG/CHP Combined

Demand (MW)	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Program MAP	395	583	732	1,790	2,113
Program RAP	74	206	396	1,071	1,325

Figure 10-2// 2036 Cumulative Annual MW Savings as % of Summer Peak Demand – All Studies Combined



	2021 Program RAP	2028 Program RAP	2036 Program RAP
DG/CHP	0.2%	0.8%	1.4%
DR	3.1%	6.7%	6.2%
Behavior	0.2%	0.3%	0.3%
EE	2.1%	6.8%	9.2%

10.1.2 Cost-Effectiveness[106]

Table 10-3 and Table 10-4 show the Program MAP and Program RAP net present values of the total benefits, costs, and net benefits, along with the TRC ratio for each study.

Table 10-3// Program MAP Cost-Effectiveness ($ in millions)

PP MAP	NPV Benefits	NPV Costs	Net Benefits	18-YR TRC Ratio
Energy Efficiency	$5,481.50	$2,887.34	$2,594.16	1.90
Behavioral	$229.38	$68.12	$161.26	3.37
Demand Response	$1,411.31	$625.26	$786.05	2.26
CHP/DG	$2,437.17	$1,786.41	$650.76	1.36
Total	**$9,559.36**	**$5,367.13**	**$4,192.23**	**1.78**

[106] 4 CSR 240-22.050(5)(A); 4 CSR 240-22.050(5)(B); 4 CSR 240-22.050(5)(D)

Table 10-4// Program RAP Cost-Effectiveness ($, in millions)

PP RAP	NPV Benefits	NPV Costs	Net Benefits	18-YR TRC Ratio
Energy Efficiency	$4,127.80	$2,026.98	$2,100.82	2.04
Behavioral	$168.90	$53.96	$114.94	3.13
Demand Response	$774.15	$346.33	$427.82	2.24
CHP/DG	$1,882.96	$1,417.62	$465.35	1.33
Total	**$6,953.81**	**$3,844.89**	**$3,108.92**	**1.81**

10.1.3 Program Budgets

Figure 10-3 and Figure 10-4 show the combined budgets for Program MAP and Program RAP for all studies.

Figure 10-3// Combined Budgets – Program MAP

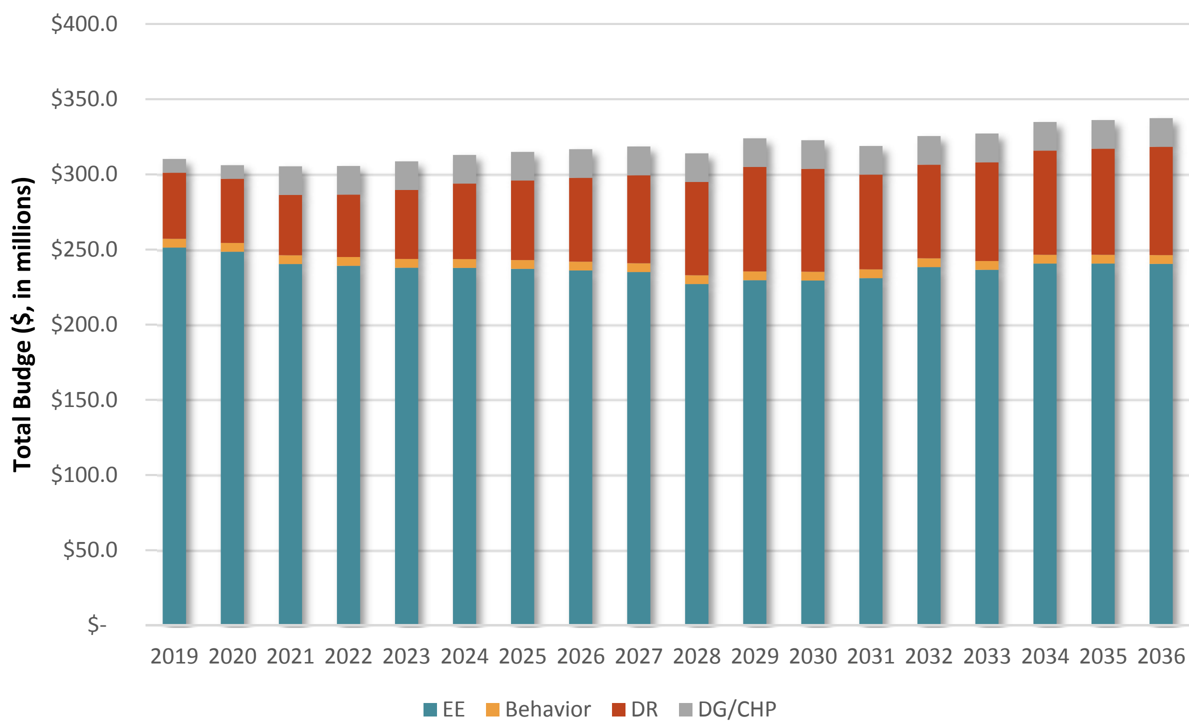
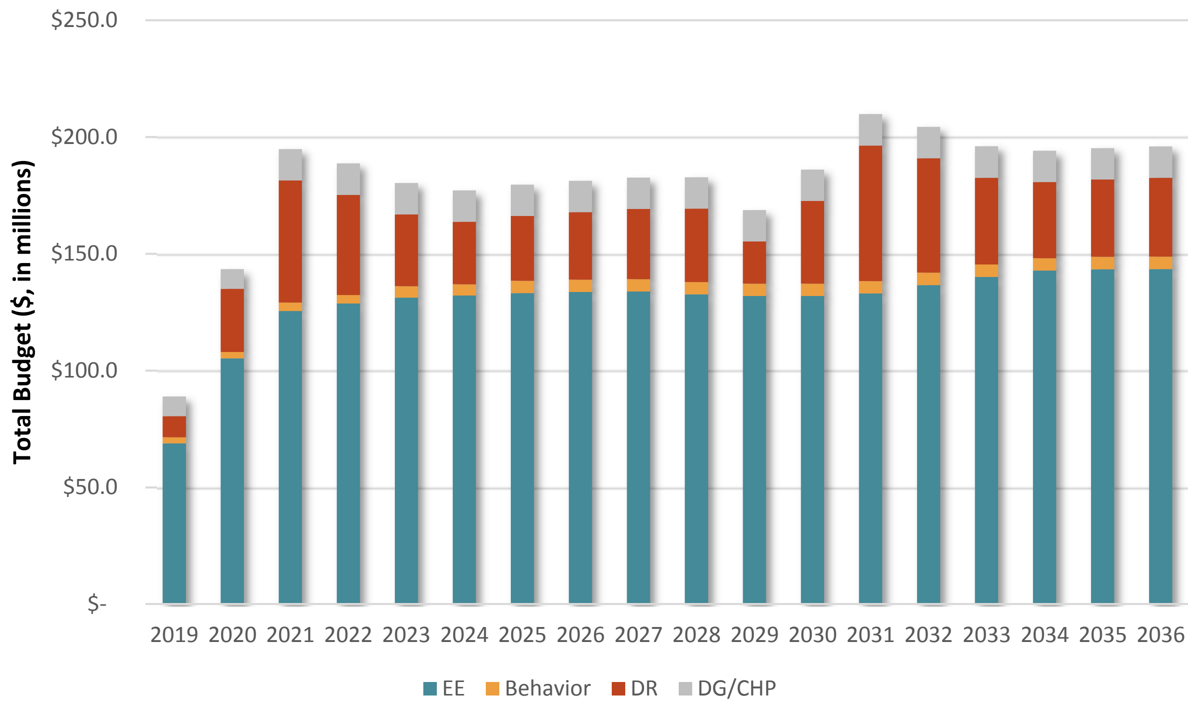


Figure 10-4// Combined Budgets – Program RAP



11 SENSITIVITY ANALYSIS[107]

In addition to the development of a base case for Program RAP potential, sensitivity analyses were performed surrounding several key assumptions in the study. GDS, Ameren Missouri, and stakeholders discussed multiple candidates for the sensitivity analysis. After considering opportunities for combining uncertainties into broader categories, the six uncertainties below were selected for analysis:

- Avoided Cost Sensitivity *(EE/DR/Behavior/DG/CHP)*
- Take Rate Sensitivity *(EE/DR/DG/CHP)*
- Attribution Sensitivity *(EE/Behavior)*
- Mandatory Inclining Block Rate *(DR only)*
- Accelerated Smart Meter Deployment *(DR only)*
- Low Income Sensitivity *(Residential EE Only)*

The remainder of this chapter describes the sensitivity selections in further detail and provides the results of the sensitivity analysis compared to the Program RAP reference case.

11.1 AVOIDED COSTS SCENARIO

Avoided costs are the primary benefit in assessing the cost-effectiveness of DSM measures. Higher avoided costs will likely result in additional measures passing the TRC cost-effectiveness screen, leading to greater savings potential; while lower avoided costs will decrease the cost-effectiveness of measures and lead to lower savings potential.

The high avoided costs scenario includes an upward 30% adjustment to the electric avoided costs, which includes a non-energy benefits increase of 10%. In the high case, natural gas avoided costs, including a 7.5% adder to reflect non-energy benefits, are also considered for measures with both electric and natural gas energy savings. Conversely, the low avoided costs scenario includes a downward adjustment of 50% relative to the reference case electric avoided costs, with natural gas savings excluded.

The table below depicts the number of cost-effective measures that were included in the high and low avoided cost sensitivity scenarios relative to the Program RAP reference case. The high avoided costs included 3% additional measures, whereas the low avoided cost scenario reduced the count of measures by 15%. The impacts of these additional or reduced measures on total Program RAP energy and demand savings are shown in section 11.7.

Table 11-1// Avoided Cost Scenario DSM measure counts

Scenario	EE	Behavior	DR	DG/CHP	Total
Program RAP	12,016	5	15	14	12,050
High Avoided Costs	12,413	6	15	14	12,448
Low Avoided Costs	10,493	1	11	13	10,518

The avoided cost sensitivity was applied to all energy efficiency, behavioral, demand response, and DG/CHP measures.

11.2 TAKE RATES SCENARIO

As discussed throughout this report, take rates represent the long-term steady state market adoption

[107] 4 CSR 240-22.050(1)(D)

rates that will be achieved by energy efficiency, demand response, and DG/CHP measures over the 18-year analysis timeframe. The take rate sensitivity analysis was performed on the Program RAP, but it is worth noting that the Program MAP reference case also representing a "high case", with aggressive take rates, lift factors, and related assumptions.

For the high take rate sensitivity, GDS examined the potential impacts of financing (where applicable) as well as increased education and outreach and more effective program delivery methods. For the low take rate sensitivity, GDS decreased the financial incentive offered by Ameren to 25% of the measure costs, and included drag factors on the Program RAP take rates to reflect reduced education and outreach and increased program delivery barriers. Because not all factors included in the take rate sensitivity are applicable to all programs and potential sectors, the high and low take rates scenarios for Program RAP were slightly different for each area of potential (i.e. *EE/DR/DG/CHP*).

For Energy Efficiency measures, GDS mapped the take rate sensitivity factors, where applicable, to each program. For example, financing was considered to be applicable for the nonresidential program offerings, as well as residential HVAC measures, because up-front customer costs to install these measures can often be significant. However, for programs such as residential lighting, where measure costs are minimal, or low-income programs, where measure costs are typically covered by the utility, the impacts of financing options were not considered. Table 11-2 presents the high and low take rate sensitivity factors applied to each EE program.

Table 11-2// Energy Efficiency Program Take Rate Sensitivities Applied to Program RAP Take Rates

		High Take Rate Scenario		Low Tate Rate Scenario
Sector	Program	Take Rate % Increase	Financing Adder of 4%	Take Rate % Decrease
Residential	Appliance Recycling Program	11%	No	33%
Residential	Efficient Products Program	33%	No	33%
Residential	Energy Efficiency Kits	33%	No	33%
Residential	HVAC Program	33%	Yes	33%
Residential	Lighting Program	11%	No	33%
Residential	Low Income Program - SF	33%	No	33%
Residential	Low Income Program - MF	33%	No	33%
C& I	Custom	33%	Yes	33%
C&I	Standard	33%	Yes	33%
Commercial	New Construction	33%	Yes	33%

For behavioral programs, there was no adjustment to the estimated take rates. The cost-effective behavioral programs are traditionally opt-out programs where the utility has full control regarding program participation. Program RAP participation levels already reflect this approach and were unlikely to be impacted by additional education and outreach. Additionally, energy report programs traditionally include no cost to the participant and are not impacted by additional financing options.

For demand response, the take rates scenarios included an upward and downward adjustment of 11% to the take rates used in the Program RAP scenario. The 11% increase was used as proxy for what might be possible considering optimal education and outreach is provided to customers.[108]

[108] 2016 Ameren Illinois Potential Study. Education and outreach component of take rate lift factor is 11%.

For DG/CHP, the take rate scenarios included an upward adjustment of 37% to the Program RAP take rates to account for possible improvements to education, program delivery, and financing options. In the low case, the take rates were decreased by 33% to reflect reduced effectiveness of education and program delivery methods.

11.3 ATTRIBUTION SCENARIO

The attribution sensitivity is relevant to Ameren in understanding the risk associated with changes in attribution that are outside the control of Ameren Missouri. In the case of DSM, attribution is the actual savings that are assigned to a program.

One element in the transition from achievable potential to program potential includes the addition of the net-to-gross ratio assumed for each measure/program. The net-to-gross (NTG) ratio identifies the fraction of program participants who would not have purchased the energy efficient measures in the absence of a program. For the Program RAP reference case, the NTG ratios assigned to each measure/end-use/program were based on the evaluated DSM programs for MEEIA Cycle 1. However, changes to DSM measure mixes, costs, savings, program delivery methods, market forces, and other factors can significantly impact future NTG ratios. In the sensitivity analysis, the high attribution case included a 15% adder while the low attribution case included a 50% deduct.

The attribution sensitivity scenario was applied to energy efficiency and behavioral measures only.

11.4 MANDATORY INCLINING BLOCK RATE SCENARIO

The mandatory inclining block rate (IBR) scenario assumes that 100% of residential customers are on the IBR rate, with no option to opt-out. Other demand response programs are run on top of this rate and the associated interactive effect on the Program RAP DR potential was captured. The Mandatory IBR scenario resulted in much higher potential than the base Program RAP because many participating residential customers were participating in two programs.

11.5 ACCELERATED SMART METER DEPLOYMENT SCENARIO[109]

The accelerated smart meter deployment scenario assumes that smart meters are deployed in four years instead of in ten years. This scenario assumes a 25% deployment rate year starting in 2019 with smart meters becoming fully deployed by 2022. Years 11 through 18 Program RAP DR potential are not affected in this scenario.

11.6 LOW INCOME SCENARIO

A final sensitivity scenario was included for the residential energy efficiency analysis to analyze the uncertainty surrounding the number of households that qualify as low-income in the Ameren Missouri service territory. The reference case estimated that approximately 50% of households[110] in the Ameren service territory qualify as low-income (up to 200% above federal poverty level). The low case assumes a more conservative estimate of the low-income population, or 30% of all households. A lower estimate of the low-income population will reduce the savings attributable to low-income specific measures and shift additional participation to the traditional residential rebate programs. The reduction in the low-income population will also decrease Program RAP budgets and costs relative to the reference case.

[109] 4 CSR 240-22.050(3)(D); 4 CSR 240-22.050(4)(C)

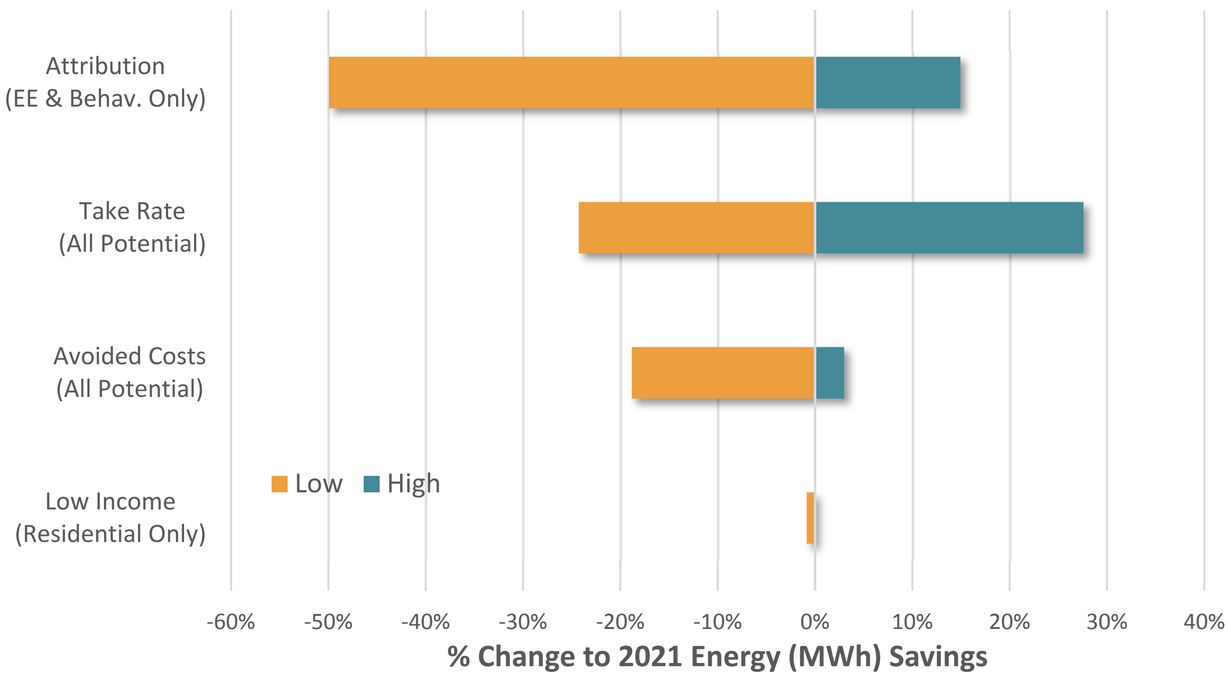
[110] Due to data limitations, the 50% estimate did not consider the effect of household size on the low income qualification therefore likely overstated the low-income population.

The low-income scenario was applied solely to the residential energy efficiency Program RAP, with minimal additional impact to the behavioral Program RAP savings due to interactive effects on savings.

11.7 SENSITIVITY RESULTS[111]

Figure 11-1 and Figure 11-2 shows the sensitivity scenarios, along with the percent difference from the Program RAP base scenario over the 2019-2021 timeframe. Figure 11-1 shows the sensitivity impacts to predicted energy (MWh) savings. Figure 11-2 shows the sensitivity scenario impacts to predicted summer peak demand (MW) savings. Similar sensitivity impacts were observed for the entire 18-year study timeframe.[112]

Figure 11-1 // Summary of Sensitivity Scenarios in 2021 – Energy (MWh)



[111] 4 CSR 240-22.050(6)(C)
[112] As noted in Section 11.5, the accelerated smart meter deployment scenario only impacts years 2019-2028.

Figure 11-2// Summary of Sensitivity Scenarios in 2021 – Demand (MW)

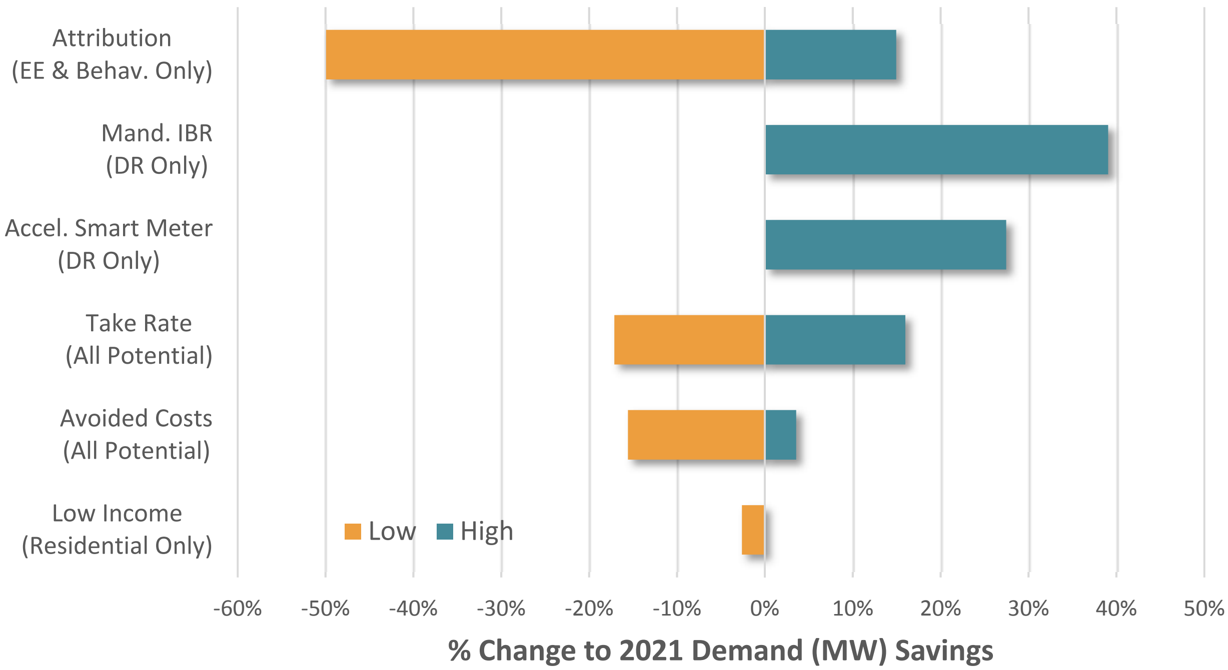


Table 11-3 provides the TRC lifetime benefits, costs, and TRC ratios for the Program RAP reference case as well as the six sensitivity scenarios.

Table 11-3// Sensitivity Scenario TRC Benefits and Costs ($ in millions)

	NPV Lifetime Benefits	NPV Program Costs	NPV Savings (Benefits - Costs)	TRC Ratio
Program RAP (Reference Case)	$6,953.8	$3,844.9	$3,108.9	1.8
High Avoided Costs	$9,976.9	$4,511.5	$5,465.4	2.2
Low Avoided Costs	$4,210.2	$2,375.8	$1,834.4	1.8
High Take Rate	$8,809.8	$4,999.1	$3,810.7	1.8
Low Take Rate	$5,606.7	$3,060.8	$2,545.9	1.8
High Attribution	$7,653.6	$3,889.0	$3,764.6	2.0
Low Attribution	$4,700.1	$3,697.4	$1,002.7	1.3
Mandatory IBR	$7,415.1	$4,030.1	$3,384.9	1.8
Accel. Smart Meter Deployment	$7,118.4	$3,935.5	$24,917.5	1.8
Reduced Low Income %	$6,876.7	$3,697.7	$3,179.0	1.9

APPENDIX A | MARKET RESEARCH DECISION MATRIX

A.1 MARKET RESEARCH FINDINGS

Appendix A - Decision

A.2 MARKET RESEARCH BIBLIOGRAPHY

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APPENDIX B | BASELINE FORECAST: AMEREN EFFICIENCY ASSUMPTIONS CODES & STANDARDS

AEO Codes and Standards.pdf

APPENDIX C | SOURCE DATA FOR ENERGY EFFICIENCY ASSUMPTIONS[113]

C.1 SOURCE DATA FOR RESIDENTIAL ENERGY EFFICIENCY ASSUMPTIONS

1_Ameren-Missouri Residential Tables fc

C.2 SOURCE DATA FOR COMMERCIAL ENERGY EFFICIENCY ASSUMPTIONS

2_Ameren-Missouri Commercial Tables f

C.3 SOURCE DATA FOR INDUSTRIAL ENERGY EFFICIENCY ASSUMPTIONS

3_Ameren-Missouri Industrial Tables for

[113] 4 CSR 240-22.050(3)(I)

APPENDIX D | SOURCE DATA FOR DEMAND RESPONSE ASSUMPTIONS [114]

Table D-1// Take Rates for Each DR Program Option

DR Option	RAP (Percent of Eligible Customers)	Source	MAP (Percent of Eligible Customers)	Source
RESIDENTIAL				
Direct Load Control				
Direct Load Control - Central Air Conditioning	20%	GDS Survey of 20 utilities (50th percentile).	31%	GDS Survey of 20 utilities (75th percentile).
Direct Load Control - Water Heating	23%	Applied ratio of RAP to MAP for DLC- Central Air Conditioning.	36%	Assumed an additional 5% participation compared to DLC AC. Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
Direct Load Control - Swimming Pool Pumps	19%	Pool Pump Demand Response Potential, Design & Engineering Services Customer Service Business Unit Southern California Edison, June 2008 (76% of survey respondents expressed an interest in an incentive-based pool pump demand response program). For RAP it is assumed that 25% of interested customers will participate.	38%	Pool Pump Demand Response Potential, Design & Engineering Services Customer Service Business Unit Southern California Edison, June 2008 (76% of survey respondents expressed an interest in an incentive-based pool pump demand response program). For MAP it is assumed that 50% of interested customers will participate.
Direct Load Control - Smart Appliances	20%	Ameren Missouri Demand Side Management Market Potential Study, Volume 4, Demand Response Analysis, EnerNOC, December 20, 2013.	31%	MAP take rates were not available in the 2013 Ameren MO DR Potential study. Used CAC MAP take rate as a reasonable proxy for smart appliance participation.
Direct Load Control - Room Air Conditioning	20%	Used Smart Appliance take rate.	31%	Use Smart Appliance take rate.
Direct Load Control of Central AC w/Smart Thermostat	25%	Demand Response Market Research:Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Participation in BYOT programs is estimated to be 25%, which is 5% higher than	36%	Demand Response Market Research:Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Participation in BYOT programs is estimated to be 5% higher than in DLC

[114] 4 CSR 240-22.050(4)(G); 4 CSR 240-22.050(5)(G)

DR Option	RAP (Percent of Eligible Customers)	Source	MAP (Percent of Eligible Customers)	Source
		in DLC programs.)		programs.)
Rate Options				
Time of Use Rate w/o Enabling Technology	28%	(1) A Review of Alternative Rate Designs, Rocky Mountain Institute, May 2016. (2) Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-In)	85%	(1) A Review of Alternative Rate Designs, Rocky Mountain Institute, May 2016. (2) Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-Out)
Time of Use Rate with Enabling Technology	36%	Applied ratio of take rates for CPP with and without enabling technology. (Opt-In)	94%	Applied ratio of take rates for CPP with and without enabling technology. (Opt Out)
Critical Peak Pricing Rate w/o Enabling Technology	17%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-In)	82%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-Out)
Critical Peak Pricing Rate with Enabling Technology	22%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-In)	91%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-Out)
Inclining Block Rate	20%	The Potential Impact of Demand-Side Rates for Ameren Missouri, The Brattle Group, Stakeholder Webinar, May 24, 2013	75%	The Potential Impact of Demand-Side Rates for Ameren Missouri, The Brattle Group, Stakeholder Webinar, May 24, 2013
Off Peak Charging of Personal Electric Vehicles - TOU Rate	57%	Plug-in Electric Vehicle and Infrastructure Analysis September 2015, Prepared for the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy by Idaho National Lab. (Opt-In)	94%	Used TOU with enabling technology take rate as most electric cars are equipped with a built-in technology that allows the vehicle to charge at specific times. (Opt-Out)
NON-RESIDENTIAL				
Direct Load Control				

DR Option	RAP (Percent of Eligible Customers)	Source	MAP (Percent of Eligible Customers)	Source
Direct Load Control - Central Air Conditioning	3%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (PacifiCorp 2014 Study, FERC 50th percentile)	14%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (PGE 2015, FERC 75th percentile)
Direct Load Control - Water Heating	7%	FERC 2012 DR Survey Data (50th percentile). Other DR potential studies (1) reviewed by GDS showed take rates ranging from 2% - 15% with an average of 7.6%.	16%	FERC 2012 DR Survey Data (75th percentile). The highest take rate in other DR potential studies (1) reviewed by GDS was 15%.
Direct Load Control - Room Air Conditioners	3%	Used DLC - Central Air Conditioning take rate	14%	Used DLC - Central Air Conditioning take rate
Direct Load Control - Swimming Pool Pumps	7%	Used Direct Load - Control Water Heating take rate. FERC 2012 DR survey data contained no utility programs targeting just commercial pool pumps. A general search for such programs by GDS also produced no useful results.	16%	Used Direct Load - Control Water Heating take rate. FERC 2012 DR survey data contained no utility programs targeting just commercial pool pumps. A general search for such programs by GDS also produced no useful results.
Direct Load Control - Commercial and Industrial Lighting	3%	Used Direct Load - Air Conditioning take rate. FERC 2012 DR survey data contained only one program targeting lighting with a take rate of .6%. A general search for such programs by GDS also produced no useful results.	14%	Used Direct Load - Air Conditioning take rate. FERC 2012 DR survey data contained only one program targeting lighting with a take rate of .6%. A general search for such programs by GDS also produced no useful results.
Direct Load Control - Agricultural Irrigation Pump	15%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Low End of Range)	30%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Average of Range)
Direct Load Control of Central AC w/Smart Thermostat	8%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Participation in BYOD programs is estimated to be 5% higher than in DLC programs.	19%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Participation in BYOD programs is estimated to be 5% higher than in DLC programs.
Rate Options				
Base Interruptible	3%	FERC 2012 DR Survey Data (50th percentile)	21%	FERC 2012 DR Survey Data (75th percentile)

DR Option	RAP (Percent of Eligible Customers)	Source	MAP (Percent of Eligible Customers)	Source
Program				
Time of Use Rate w/o Enabling Technology	13%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-In)	74%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-Out)
Time of Use Rate with Enabling Technology	16%	Applied ratio of take rates for CPP with and without enabling technology. (Opt-In)	81%	Applied ratio of take rates for CPP with and without enabling technology. (Opt-Out)
Electric Thermal Storage – Cooling Rate	16%	Used TOU with enabling technology take rate (Opt-In)	81%	Used TOU with enabling technology take rate (Opt-Out)
Critical Peak Pricing Rate w/o Enabling Technology	18%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-In)	63%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-Out)
Critical Peak Pricing Rate with Enabling Technology	20%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-In)	69%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-Out)
Off Peak Charging of Golf Carts - TOU Rate	16%	Used TOU with enabling technology take rate (Opt-In). It is assumed that an enabling system will be installed to manage charging.	81%	Used TOU with enabling technology take rate (Opt-Out). It is assumed that an enabling system will be installed to manage charging.
Off Peak Charging of Other Plug-In Utility Vehicles - TOU Rate	16%	Used TOU with enabling technology take rate (Opt-In). It is assumed that an enabling system will be installed to manage charging.	81%	Used TOU with enabling technology take rate (Opt-Out). It is assumed that an enabling system will be installed to manage charging.
Off Peak Charging of Electric Feet Vehicles - TOU Rate	60%	Ameren Missouri estimate.	94%	Used TOU with enabling technology take rate as most electric cars are equipped with a built-in technology that allows the vehicle to charge at specific times (Opt-Out)
Aggregator Programs				

DR Option	RAP (Percent of Eligible Customers)	Source	MAP (Percent of Eligible Customers)	Source
18. Capacity Bidding Programs	1%	Capacity bidding programs at PG&E and SCE in California have low (less than 1%) and declining enrollments as shown in the Annual CBP Evaluations (2). Long term forecasts of enrollments are also expected to remain at current levels. (3)	8%	Demand Response Market Potential in Xcel Energy's Northern States Power Service Territory, The Brattle Group, April 2014. "Customer interest in such a program was modest based on market research, with around 10% of small/medium customers and 8% of large customers being interested."
19. Demand Bidding Programs	1%	Demand bidding programs at PG&E and SCE in California have low (less than 1%) and declining enrollments as shown in the Annual CBP Evaluations (4). Long term forecasts of enrollments are also expected to remain at current levels. (3)	10%	Demand Response Market Potential in Xcel Energy's Northern States Power Service Territory, The Brattle Group, April 2014. "Customer interest in such a program was modest based on market research, with around 10% of small/medium customers and 8% of large customers being interested."

1) Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources, 2013-2032 Volume I, PacifiCorp, Cadmus, March 2013
2) 2014 Statewide Load Impact Evaluation of California Aggregator Demand Response Programs, Christensen Associates Energy Consulting.
3) Executive Summary: 2015–2025 Demand Response Portfolio of Southern California Edison Company April 1, 2015, Prepared for Southern California Edison Co. by Candice A. Churchwell, Senior Consultant, Nexant, Inc.
4) 2013, 2014, and 2015 Load Impact of California Statewide Demand Bidding Programs for Non-Res Customers by Christensen Associates Energy Consulting and FERC 2012 Demand Response Study.

Table D-2// Residential Central Air Conditioning Direct Load Control Program Take Rates for Other Utilities

Source: GDS Survey

Utility	DLC AC Cumulative Participating Customers	Eligible Customers in Data Year	Take Rate	Data Year
Dakota Electric Association	33,000	61,875	53.33%	2015
PEPCO	N/A	N/A	53.00%	2013
SMECO	36,500	70,200	51.99%	2015
BG&E	349,758	924,000	37.85%	2013
DPL	N/A	N/A	37.00%	2013
NOVEC	35,000	121,500	28.81%	2015
Public Service Company of New Mexico	36,611	130,500	28.05%	2015
Rappahannock Electric Coop	10,500	47,200	22.25%	2015
Sacramento Municipal Utility District	94,227	427,440	22.04%	2015
Connexus Energy	22,000	102,300	21.51%	2015

Utility	DLC AC Cumulative Participating Customers	Eligible Customers in Data Year	Take Rate	Data Year
DTE Electric Co.	277,186	1,439,815	19.25%	2015
Interstate Power and Light Co	50,000	300,000	16.67%	2015
PECO	97,600	903,704	10.80%	2012
Dairyland Power Cooperative	16,896	169,216	9.98%	2013
PPL	42,000	700,000	6.00%	2012
FE: Met-Ed	21,369	410,942	5.20%	2012
Georgia Power	62,411	1,352,233	4.62%	2013
FE: Penelec	11,860	348,824	3.40%	2012
FE: Penn Power	2,806	87,688	3.20%	2012
Duquesne	1,491	331,333	0.45%	2012
TOTAL	**1,201,215**	**7,928,769**	**21.77%**	**N/A**

Load Reduction Sources

Table D-3// Residential Per Participant CP Demand Reduction Sources

DR Program Options	Per Participant CP Demand Reduction	CP Demand Reduction Source
Direct Load Control		
Control of Central Air Conditioners with Load Control Switch	1.06 kW	2012 FERC Demand Response Survey Data (Reported realized savings data for 20 utility programs, adjusted to account for peak summer temperature differences using NOAA Normal Max Summer Temperature Data, 1981-2010)
Control of Electric Water Heaters	0.4 kW	Average of Brattle Study (0.4 kW), Cadmus PSE potential study (0.57 kW with 94% effective rate applied), and Cadmus evaluation for Kootenai (0.26 kW)
Control of Room Air Conditioners	0.504 kW	GDS Calculations using Enernoc saturations, UECs, and peak factors. US DOE report on Use of Residential Smart Appliances for Peak-Load Shifting and Spinning Reserves, 2010.
Control of Swimming Pool Pumps	1.36 kW	Southern California Edison Pool Pump Demand Response Potential Report, 2008.

DR Program Options	Per Participant CP Demand Reduction	CP Demand Reduction Source
Control of Air Conditioners with Controllable "Smart" Thermostats (ie Nest, Ecobee)	0.92 kW	87% of Load Switch Control. Sources: Smart Thermostats: An Alternative to Load Control Switches? Trends and Strategic Options to Consider for Residential Load Control Programs; 2016 Demand Response Potential Study Conducted by GDS for several Michigan utilities (Confidential pilot program report)
Smart Appliances	0.072 kW	GDS Calculations using Enernoc saturations, UECs, and peak factors. US DOE report on Use of Residential Smart Appliances for Peak-Load Shifting and Spinning Reserves, 2010.
Rate Options		
Time of Use Rate w/o Enabling Technology	3.20%	The Potential Impact of Demand-Side Rates for Ameren Missouri, The Brattle Group, Stakeholder Webinar, May 24, 2013
Time of Use Rate with Enabling Technology for Smart Appliances	6.08%	Dynamic Pricing: Transitioning from Experiments to Full Scale Deployments, Michigan Retreat on Peak Shaving to Reduce Wasted Energy, The Brattle Group, August 06, 2014.
Critical Peak Pricing Rate w/o Enabling Technology	12.95%	Impacts on Ameren TOU CPP Pilot Results
Critical Peak Pricing Rate with Enabling Technology for Smart Appliances	23.44%	Impacts on Ameren TOU CPP Pilot Results
Electric Vehicle Charging Station Off Peak (Personal and Fleet)	0.94 kW	GDS Calculation
Inclining Block Rate	4.40%	The Potential Impact of Demand-Side Rates for Ameren Missouri, The Brattle Group, Stakeholder Webinar, May 24, 2013

Table D-4// Non-Residential Per Participant CP Demand Reduction Sources

DR Program Options	Per Participant CP Demand Reduction	CP Demand Reduction Source
Direct Load Control		
Control of Central Air Conditioners with Load Control Switch	1.6 kW	2012 FERC Demand Response Survey Data (Reported realized savings data for 14 utility programs, adjusted to account for peak summer temperature differences using NOAA Normal Max Summer Temperature Data, 1981-2010)
Control of Electric Water Heaters	0.9 kW	2012 FERC Demand Response Survey Data (Reported realized savings data for 6 utility programs)
Control of Room Air Conditioners	0.761 kW	Ratio from Residential/Non-Residential Central AC applied to Residential RAC

DR Program Options	Per Participant CP Demand Reduction	CP Demand Reduction Source
Electric Thermal Storage – Cooling	19.4 kW (buildings with chillers)	MISO Demand Response, EE, DG Potential Study: Supplemental Program Slides. Value for Local Resource Zone 5 (Includes Ameren MO service area)
Control of Swimming Pool Pumps	2 kW	Rocky Mountain Institute, LIPA Edge Program Profile
Control of Commercial Lighting - On/Off, Dimming	8.75% of total CP demand	Business Energy Advisor/E Source, Strategies for Commercial and Industrial Demand Response; LIGHTING CALIFORNIA'S FUTURE: COST-EFFECTIVE DEMAND RESPONSE, Prepared For: California Energy Commission By: NEV Electronics, LLC, California Lighting Technology Center, March 2011; Lighting Controls Association, Lighting Control and Demand Response, By Craig DiLouie, on May 20, 2014; Demonstration and Evaluation of lighting technologies and Applications, Lighting Research Center, Field Test Issue 6, October 2011; What is the relation between energy consumption savings and peak load savings and how can this affect future energy conservation requirements? - Study conducted by the City of Toronto.
Agricultural Irrigation Pump Control	44 kW	2012 FERC Demand Response Survey Data (Reported realized savings data for 17 utility programs)
Control of Air Conditioners with Controllable "Smart" Thermostats (i.e. Nest, Ecobee)	1.4 kW	87% of Load Switch Control. Sources: Smart Thermostats: An Alternative to Load Control Switches? Trends and Strategic Options to Consider for Residential Load Control Programs; 2016 Demand Response Potential Study Conducted by GDS for several Michigan utilities (Confidential pilot program report)
Rate Options		
Interruptible Rate	41.3 KW	MISO Demand Response, EE, DG Potential Study: Supplemental Program Slides, July 31, 2015. Value for Local Resource Zone 5 (Includes Ameren MO service area)
Time of Use Rate w/o Enabling Technology	2%	The Potential Impact of Demand-Side Rates for Ameren Missouri, The Brattle Group, Stakeholder Webinar, May 24, 2013
Time of Use Rate with Enabling Technology	3.80%	Dynamic Pricing: Transitioning from Experiments to Full Scale Deployments, Michigan Retreat on Peak Shaving to Reduce Wasted Energy, The Brattle Group, August 06, 2014.
Critical Peak Pricing Rate w/o Enabling Technology	11.30%	The Potential Impact of Demand-Side Rates for Ameren Missouri, The Brattle Group, Stakeholder Webinar, May 24, 2013
Critical Peak Pricing Rate with Enabling Technology	21.47%	Dynamic Pricing: Transitioning from Experiments to Full Scale Deployments, Michigan Retreat on Peak Shaving to Reduce Wasted Energy, The Brattle Group, August 06, 2014.

DR Program Options	Per Participant CP Demand Reduction	CP Demand Reduction Source
Off Peak Charging of Golf Carts	0.75 kW per cart	Demand Response and Load Management Strategies for Electric Forklifts and Non-Road EV Fleets, Richard Cromie Program Manager, Southern California Edison Co.
Off Peak Charging of Other Plug-In Utility Vehicles	1.7 kW per utility vehicle	Demand Response and Load Management Strategies for Electric Forklifts and Non-Road EV Fleets, Richard Cromie Program Manager, Southern California Edison Co.
Electric Vehicle Charging Station Off Peak (Personal and Fleet)	0.94 kW	GDS Calculation.
Aggregator Programs		
Capacity Bidding Programs	19.50%	2014 Statewide Load Impact Evaluation of California Aggregator Demand Response Programs. 2015. Christensen Associates Energy Consulting.
Demand Bidding Programs	7%	Average taken from: 2013, 2014, and 2015 Load Impact of California Statewide Demand Bidding Programs for Non-Res Customers by Christensen Associates Energy Consulting and FERC 2012 Demand Response Study.

Eligible Customers

Table D-5// Eligible Residential Customers for Maximum Achievable Potential in Each DR Program Option

DR Program Option	Saturation / Hierarchy	Saturation Source	Eligible Residential Customers 2023	Eligible Residential Customers 2028	Eligible Residential Customers 2036
Critical Peak Pricing Rate with Enabling Technology	86% of Residential Customers with smart meters (91% Central AC Saturation * 95% of Customers are Offered LC Device)	Ameren / EnerNOC 2013 Study, Volume 2; FERC	275,297	553,833	558,850
Critical Peak Pricing Rate without Enabling Technology	100% of Residential Customers with smart meters minus CPP with Tech Participants	GDS Assumption	280,224	563,744	568,852
Time of Use Rate without Enabling Technology	100% of Residential Customers with smart meters minus all cost-effective CPP and TOU with Technology Participants	GDS Assumption	581,184	101,474	102,393

DR Program Option	Saturation / Hierarchy	Saturation Source	Eligible Residential Customers 2023	Eligible Residential Customers 2028	Eligible Residential Customers 2036
Inclining Block Rate	100% of Residential Customers minus all cost-effective CPP and TOU Participants	GDS Assumption	581,184	101,474	102,393
DLC Central AC Switch	91% of Residential Customers minus all cost-effective CPP, TOU, and IBR Participants	Ameren / EnerNOC 2013 Study, Volume 2	6,888	0	0
Plug-In Electric Vehicle Charging Stations Off Peak	100% of PEVs (20% Commercial, 80% Residential)	Provided by Ameren	7,303	19,613	39,575

Table D-6// Eligible Residential Customers for Realistic Achievable Potential in Each DR Program Option

DR Program Option	Saturation / Hierarchy	Saturation Source	Eligible Residential Customers 2023	Eligible Residential Customers 2028	Eligible Residential Customers 2036
Critical Peak Pricing Rate with Enabling Technology	86% of Residential Customers with smart meters (91% Central AC Saturation * 95% of Customers are Offered LC Device)	Ameren / EnerNOC 2013 Study, Volume 2; FERC	458,828	923,055	931,416
Critical Peak Pricing Rate without Enabling Technology	100% of Residential Customers with smart meters minus CPP with Tech Participants	GDS Assumption	429,802	864,660	872,493
Time of Use Rate with Enabling Technology	86% of Residential Customers with smart meters (91% Central AC Saturation * 95% of Customers are Offered LC Device) minus all CPP Participants	Ameren / EnerNOC 2013 Study, Volume 2; KCP&L Demand-Side Resource Potential Study Report - DR, August 2013	284,820	572,991	578,181
Time of Use Rate without Enabling Technology	100% of Residential Customers minus all cost-effective CPP and TOU with Technology Participants	GDS Assumption	887,480	717,668	724,170
Inclining Block Rate	100% of Residential Customers minus all cost-effective CPP and TOU Participants	GDS Assumption	887,480	717,668	724,170

DR Program Option	Saturation / Hierarchy	Saturation Source	Eligible Residential Customers 2023	Eligible Residential Customers 2028	Eligible Residential Customers 2036
DLC Central AC by Switch	91% of Residential Customers minus all cost-effective CPP, TOU, and IBR Participants	Ameren / EnerNOC 2013 Study, Volume 2	614,450	478,038	482,369
DLC Central AC by Smart Thermostat	55.5% of Residential Customers (91% CAC Saturation * 61% WiFi Saturation) minus all cost-effective CPP, TOU, and IBR Participants	Ameren / EnerNOC 2013 Study, Volume 2; https://techcrunch.com/2012/04/05/study-61-of-u-s-households-now-have-wifi/	237,728	99,100	99,998
DLC Pool Pumps	5.5% of Residential Customers minus all cost-effective CPP, TOU, and IBR Participants	Ameren / EnerNOC 2013 Study, Residential Market Profile Summary Tables Spreadsheet	0	0	0
DLC Room AC	9% of Residential Customers minus all cost-effective CPP, TOU, and IBR Participants	Ameren / EnerNOC 2013 Study, Volume 2	0	0	0
DLC Electric Water Heaters	48% of Residential Customers minus all cost-effective CPP, TOU, and IBR Participants	Ameren / EnerNOC 2013 Study, Volume 2	158,010	18,914	19,085
DLC Smart Appliances	20% of Central AC Switch Participants with smart meters (Saturations of Each Appliance Included in Load Reduction Value) minus all cost-effective CPP, TOU, and IBR Participants	Ameren / EnerNOC 2013 Study, Residential Market Profile Summary Tables Spreadsheet	0	0	0
Off Peak Plug-In Electric Vehicle Charging Rate	100% of PEVs (20% Commercial, 80% Residential)	Provided by Ameren	7,303	19,613	39,575

Table D-7// Eligible Commercial Customers for Maximum Achievable Potential in Each DR Program Option

DR Program Option	Saturation / Hierarchy	Saturation Source	Eligible Commercial Customers 2023	Eligible Commercial Customers 2028	Eligible Commercial Customers 2036

DR Program Option	Saturation / Hierarchy	Saturation Source	Eligible Commercial Customers 2023	Eligible Commercial Customers 2028	Eligible Commercial Customers 2036
Critical Peak Pricing Rate with Enabling Technology	77% of Commercial SGS, LGS, and SPS Customers with smart meters (80.85% Central AC Saturation * 95% of Customers are Offered LC Device)	EIA CBECS, average of "West North Central" and "East South Central" regions; FERC	37,390	75,444	75,777
Critical Peak Pricing Rate without Enabling Technology	100% of Commercial SGS, LGS, and SPS Customers with smart meters minus CPP with Technology Participants	GDS Assumption	55,334	111,653	112,146
DLC Central AC- One-Way Switch	80.85% of Commercial SGS Customers minus all cost-effective CPP and TOU Participants	EIA CBECS, average of "West North Central" and "East South Central" regions	61,890	1,224	1,221
DLC AC - Smart Controllabl e Thermostat s	49.3% of Commercial SGS Customers (80.85% CAC Saturation * 61% WiFi Saturation) minus all cost-effective CPP and TOU Participants	EIA CBECS, average of "West North Central" and "East South Central" regions; https://techcrunch.com/2012/04/05/study-61-of-u-s-households-now-have-wifi/	2,900	0	0
Capacity Bidding	100% of Commercial LGS, SPS, and LPS Customers with smart meters minus all cost-effective CPP, TOU, and DLC Participants	GDS Assumption	1,396	2,839	2,862
Demand Bidding	100% of Commercial SGS Customers with smart meters minus all cost-effective CPP, TOU, DLC, and Capacity Bidding Participants	GDS Assumption	0	15,767	15,835

Table D-8// Eligible Commercial Customers for Realistic Achievable Potential in Each DR Program Option

DR Program Option	Saturation / Hierarchy	Saturation Source	Eligible Commercial Customers 2023	Eligible Commercial Customers 2028	Eligible Commercial Customers 2036

DR Program Option	Saturation / Hierarchy	Saturation Source	Eligible Commercial Customers 2023	Eligible Commercial Customers 2028	Eligible Commercial Customers 2036
Critical Peak Pricing Rate with Enabling Technology	77% of Commercial SGS, LGS, and SPS Customers with smart meters (80.85% Central AC Saturation * 95% of Customers are Offered LC Device)	EIA CBECS, average of "West North Central" and "East South Central" regions; FERC	62,316	125,741	126,296
Critical Peak Pricing Rate without Enabling Technology	100% of Commercial SGS, LGS, and SPS Customers with smart meters minus CPP with Technology Participants	GDS Assumption	68,670	138,561	139,173
Time of Use Rate with Enabling Technology	77% of Commercial SGS Customers with smart meters (80.85% Central AC Saturation * 95% of Customers are Offered LC Device) minus all CPP Participants	EIA CBECS, average of "West North Central" and "East South Central" regions; KCP&L Demand-Side Resource Potential Study Report - DR, August 2013	33,387	67,352	67,641
Time of Use Rate without Enabling Technology	100% of Commercial SGS Customers minus all cost-effective CPP and TOU with Technology Participants	GDS Assumption	121,410	92,037	92,434
Interruptible Rate	100% of Commercial LGS and SPS Customers minus all cost-effective CPP and TOU Participants	GDS Assumption	0	0	0
Thermal Electric Storage-Cooling Rate	2.41% of Commercial SGS, LGS, and SPS Customers minus all cost-effective CPP and TOU Participants	EIA CBECS, average of "West North Central" and "East South Central" regions for chillers	3,907	3,942	3,960
Off Peak Golf Cart Charging	100% of Golf Courses in Ameren's Service Area	golflink.com, EIA data on residential customers	153	153	153

DR Program Option	Saturation / Hierarchy	Saturation Source	Eligible Commercial Customers 2023	Eligible Commercial Customers 2028	Eligible Commercial Customers 2036
Off Peak Utility Vehicle Charging	100% of Electric Commercial Utility Vehicles in Ameren's Service Area	DR & Load Management Strategies for Electirc Forklifts and Non-Road EV Fleets, Southern California Edison Co; EIA Form 861 Data	6,697	6,754	6,783
Off Peak Plug-In Electric Vehicle Charging Rate	100% of PEVs (20% Commercial, 80% Residential)	Provided by Ameren	1,826	4,903	9,894
DLC Central AC by Switch	80.85% of Commercial SGS Customers minus all cost-effective CPP and TOU Participants	EIA CBECS, average of "West North Central" and "East South Central" regions	92,383	62,757	63,026
DLC Central AC by Smart Thermostat	49.3% of Commercial SGS Customers (80.85% CAC Saturation * 61% WiFi Saturation) minus all cost-effective CPP and TOU Participants	EIA CBECS, average of "West North Central" and "East South Central" regions; https://techcrunch.com/2012/04/05/study-61-of-u-s-households-now-have-wifi/	44,589	14,544	14,604
DLC Lighting	25.5% of Industrial SGS Customers (Customers with T12 Lighting)	2010 U.S. Lighting Market Characterization. US DOE. Jan 2012. Table 4.2.	121,261	122,322	122,854
DLC Electric Water Heaters	28% of Commercial SGS Customers minus all cost-effective CPP and TOU Participants	Ameren / EnerNOC 2013 Study, Volume 3	12,275	0	0
DLC Pool Pumps	4.6% of Commercial SGS Customers minus all cost-effective CPP and TOU Participants	Ameren / EnerNOC 2013 Study, Volume 3	0	0	0

DR Program Option	Saturation / Hierarchy	Saturation Source	Eligible Commercial Customers 2023	Eligible Commercial Customers 2028	Eligible Commercial Customers 2036
DLC Room AC	5% of Commercial SGS Customers minus all cost-effective CPP and TOU Participants	Ameren / EnerNOC 2013 Study, Business Program Interest Survey Questionnaire Data	7,579	7,645	7,678
DLC Irrigation-Agriculture	100% of Irrigated Farms in Ameren's Service Area minus all cost-effective CPP and TOU Participants	1: USDA, 2013 Farm and Ranch Irrigation Survey, Table 12: On-Farm Energy Expense for Pumping Irrigation Water by Water Source and Type of Energy, State of MO; 2: Based on Percent of Zip Codes in Each County Served by Ameren MO. Zip Codes Served provided by Ameren MO.	0	0	0
Capacity Bidding	100% of Commercial LGS, SPS, and LPS Customers with smart meters minus all cost-effective CPP, TOU, and DLC Participants	GDS Assumption	3,740	7,569	7,613
Demand Bidding	100% of Commercial SGS Customers with smart meters minus all cost-effective CPP, TOU, DLC, and Capacity Bidding Participants	GDS Assumption	49,817	104,207	104,657

Table D-9// Eligible Industrial Customers for Maximum Achievable Potential in Each DR Program Option

DR Program Option	Saturation / Hierarchy	Saturation Source	Eligible Industrial Customers 2023	Eligible Industrial Customers 2028	Eligible Industrial Customers 2036
Critical Peak Pricing Rate with Enabling Technology	20% of Commercial SGS, LGS, and SPS Customers with smart meters (21% Central AC Saturation * 95% of Customers are Offered LC Device)	Ameren / EnerNOC 2013 Study, Volume 3; FERC	240	477	476
Critical Peak Pricing Rate without Enabling Technology	100% of Industrial SGS, LGS, and SPS Customers with smart meters minus CPP with Technology Participants	GDS Assumption	1,840	3,660	3,650
Interruptible Rate	100% of Industrial LGS and SPS Customers with smart meters minus all cost-effective CPP and TOU Participants	GDS Assumption	0	0	0
Capacity Bidding	100% of Industrial LGS, SPS, and LPS Customers with smart meters minus all cost-effective CPP, TOU, Interruptible, and DLC Participants	GDS Assumption	218	440	441
Demand Bidding	100% of Industrial SGS Customers with smart meters minus all cost-effective CPP, TOU, Interruptible, and DLC Participants	GDS Assumption	480	948	943

Table D-10// Eligible Industrial Customers for Realistic Achievable Potential in Each DR Program Option

DR Program Option	Saturation / Hierarchy	Saturation Source	Eligible Industrial Customers 2023	Eligible Industrial Customers 2028	Eligible Industrial Customers 2036
Critical Peak Pricing Rate with Enabling Technology	20% of Commercial SGS, LGS, and SPS Customers with smart meters (21% Central AC Saturation * 95% of Customers are Offered LC Device)	Ameren / EnerNOC 2013 Study, Volume 3; FERC	400	796	794
Critical Peak Pricing Rate without Enabling Technology	100% of Industrial SGS, LGS, and SPS Customers with smart meters minus CPP with Technology Participants	GDS Assumption	1,926	3,830	3,819

DR Program Option	Saturation / Hierarchy	Saturation Source	Eligible Industrial Customers 2023	Eligible Industrial Customers 2028	Eligible Industrial Customers 2036
Time of Use Rate with Enabling Technology	20% of Commercial SGS Customers with smart meters (21% Central AC Saturation * 95% of Customers are Offered LC Device) minus all cost-effective CPP Participants	Ameren / EnerNOC 2013 Study, Volume 3; KCP&L Demand-Side Resource Potential Study Report - DR, August 2013	0	0	0
Time of Use Rate without Enabling Technology	100% of Industrial SGS Customers minus all cost-effective CPP and TOU with Technology Participants	GDS Assumption	2,434	1,990	1,983
Interruptible Rate	100% of Industrial LGS and SPS Customers with smart meters minus all cost-effective CPP and TOU Participants	GDS Assumption	148	301	303
Thermal Electric Storage-Cooling Rate	2.41% of Industrial SGS, LGS, and SPS Customers minus all cost-effective CPP, TOU, and Interruptible Participants	EIA CBECS, average of "West North Central" and "East South Central" regions for chillers	90	89	89
Off Peak Utility Vehicle Charging	100% of Electric Industrial Utility Vehicles in Ameren's Service Area	DR & Load Management Strategies for Electirc Forklifts and Non-Road EV Fleets, Southern California Edison Co; EIA Form 861 Data	6,697	6,754	6,783
DLC Central AC by Switch	21% of Industrial SGS Customers minus all cost-effective CPP, TOU, and Interruptible Participants	Ameren / EnerNOC 2013 Study, Volume 3	174	0	0
DLC Central AC by Smart Thermostat	12.8% of Industrial SGS Customers (21% CAC Saturation * 61% WiFi Saturation) minus all cost-effective CPP, TOU, and Interruptible Participants	Ameren / EnerNOC 2013 Study, Volume 3; https://techcrunch.com/2012/04/05/study-61-of-u-s-households-now-have-wifi/	0	0	0

DR Program Option	Saturation / Hierarchy	Saturation Source	Eligible Industrial Customers 2023	Eligible Industrial Customers 2028	Eligible Industrial Customers 2036
DLC Lighting	24.1% of Industrial SGS Customers (Customers with T12 Lighting) minus all cost-effective CPP, TOU, and Interruptible Participants	2010 U.S. Lighting Market Characterization. US DOE. Jan 2012. Table 4.2.	2,125	1,684	1,677
DLC Electric Water Heaters	28% of Industrial SGS Customers minus all cost-effective CPP, TOU, and Interruptible Participants	Ameren / EnerNOC 2013 Study, Volume 3	374	0	0
DLC Room AC	5% of Industrial SGS Customers minus all cost-effective CPP, TOU, and Interruptible Participants	Ameren / EnerNOC 2013 Study, Business Program Interest Survey Questionnaire Data	0	0	0
Capacity Bidding	100% of Industrial LGS, SPS, and LPS Customers with smart meters minus all cost-effective CPP, TOU, Interruptible, and DLC Participants	GDS Assumption	471	944	944
Demand Bidding	100% of Industrial SGS Customers with smart meters minus all cost-effective CPP, TOU, Interruptible, and DLC Participants	GDS Assumption	1,125	2,230	2,222

APPENDIX E | SOURCE DATA FOR CHP/DG ASSUMPTIONS

CHP DG Source
Data Assumptions

Compliance References

Draft Report

DSM Market Potential Study

Prepared for:

Ameren Missouri

Prepared by:

GDS Associates, Inc.
ENGINEERS & CONSULTANTS
1850 Parkway Place
Suite 800
Marietta, Georgia 30067
www.gdsassociates.com