

Characterization Data – Renewable and Storage Resources⁴

Resource Option	Renewable Resource	Plant Maintenance Pattern, week/year	Water Consumption, gal/min	VOM Escalation Rate, percent	Present Worth Discount Rate, percent	Fixed Charge Rate, percent	Candidate Option	Cost Rank	LCOE, ¢/kWh
Compressed Air Energy Storage	n/a	n/a	n/a	3.00%	7.67%	12.03%	No	10	18.30
Pumped Hydro Storage	n/a	n/a	n/a	3.00%	7.67%	11.83%	Yes	13	21.77
Wind	Wind	n/a	n/a	3.00%	7.70%	12.22%	Yes	2	10.81
Solar	Solar	n/a	n/a	3.00%	7.70%	12.22%	Yes	16	37.3
Co-firing (St. Louis Region) 0 Note 1	Biomass	3-3-3-3-3-8	0	3.00%	7.70%	12.49%	Yes	1	5.90
Wood-fired Standleone (Ellington Region)	Biomass	3-3-3-3-3-8	300 to 400	3.00%	7.70%	12.49%	No	15	29.02
Poultry-litter Standleone (Monett Region)	Biomass	3-3-3-3-3-8	300 to 400	3.00%	7.70%	12.49%	No	12	20.68
Ozark Beach	Hydro	1	0	3.00%	7.70%	12.42%	No	6	11.80
Clearwater	Hydro	1	0	3.00%	7.70%	12.42%	No	11	18.92
Pomme De Terre	Hydro	1	0	3.00%	7.70%	12.42%	No	4	11.01
Mississippi L&D 21	Hydro	1	0	3.00%	7.70%	12.42%	No	14	23.87
Bridgeton	LFG	1-1-3	0	3.00%	7.70%	14.18%	No	5	11.42
Fred Weber	LFG	1-1-3	0	3.00%	7.70%	14.18%	Yes	3	10.90
Lemons East	LFG	1-1-3	0	3.00%	7.70%	14.18%	No	9	14.17
Missouri Pass	LFG	1-1-3	0	3.00%	7.70%	14.18%	No	7	12.86
Veolia Maple Hill	LFG	1-1-3	0	3.00%	7.70%	14.18%	No	8	13.94
Mercer County 1	AD	1-1-3	0 to 20	3.00%	7.70%	14.18%	No	17	39.77
Sullivan County 1	AD	1-1-3	0 to 20	3.00%	7.70%	14.18%	No	18	40.53
Gentry County 1	AD	1-1-3	0 to 20	3.00%	7.70%	14.18%	No	22	42.79
Putnam County 1	AD	1-1-3	0 to 20	3.00%	7.70%	14.18%	No	23	42.99
Sullivan County 2	AD	1-1-3	0 to 20	3.00%	7.70%	14.18%	No	23	42.99
Gentry County 2	AD	1-1-3	0 to 20	3.00%	7.70%	14.18%	No	25	43.63
Sullivan County 3	AD	1-1-3	0 to 20	3.00%	7.70%	14.18%	No	26	43.77
Mercer County 2	AD	1-1-3	0 to 20	3.00%	7.70%	14.18%	No	30	48.18
Putnam County 2	AD	1-1-3	0 to 20	3.00%	7.70%	14.18%	No	18	40.53
Sullivan County 4	AD	1-1-3	0 to 20	3.00%	7.70%	14.18%	No	20	40.80
Vernon County	AD	1-1-3	0 to 20	3.00%	7.70%	14.18%	No	28	46.20
Johnson County	AD	1-1-3	0 to 20	3.00%	7.70%	14.18%	No	21	41.66
Lincoln County	AD	1-1-3	0 to 20	3.00%	7.70%	14.18%	No	27	45.80
Lewis County	AD	1-1-3	0 to 20	3.00%	7.70%	14.18%	No	29	47.68

CAES was excluded because Ameren Missouri decided to evaluate pumped storage as the mass energy storage technology. The anaerobic digestion (AD) and biomass stand-alone projects were excluded based on cost. The remaining landfill gas and hydro projects were excluded because they are relatively small and opportunistic in nature. Ameren Missouri will continue to consider these projects but they were not analyzed further in this IRP.⁵ Ozark Beach was disqualified since it is owned and operated by Empire District Electric.

⁴ 4 CSR 240-22.040(2); 4 CSR 240-22.040(9)(B); 4 CSR 240-22.040(1)(H); 4 CSR 240-22.040(1)(K)3.; 4 CSR 240-22.040(2)(C);

4 CSR 240-22.040(9)(A)2.; 4 CSR 240-22.040(9)(A); 4 CSR 240-22.040(9)(A)1.

⁵ 4 CSR 240-22.040(9)(A)3.

Characterization Data – Renewable and Storage Resources⁶

Capital Cost Uncertainty Distribution.					
Deviation	-30%	-15%	0%	15%	30%
Probability	5%	25%	40%	25%	5%

Fixed O&M Cost Uncertainty Distribution.					
Deviation	-30%	-15%	0%	15%	30%
Probability	5%	25%	40%	25%	5%

Variable O&M Cost Uncertainty Distribution.				
Biomass Combustion – Standalone	-50%	Base	50%	
Deviation	25%	50%	25%	
Probability				
Biomass Combustion – Co-firing	-60%	Base	40%	80%
Deviation	15%	50%	25%	10%
Probability				
LFG – Reciprocating Engine	-50%	Base	50%	
Deviation	25%	50%	25%	
Probability				
LFG – Combustion Turbine	-50%	Base	50%	
Deviation	25%	50%	25%	
Probability				
Hydroelectric	-50%	Base	50%	
Deviation	25%	50%	25%	
Probability				

Forced Outage Rate Uncertainty Distribution.				
Biomass Combustion – Standalone	7%	10%	13%	
EFOR				
EFORd	7%	10%	12%	
Probability	-25%	50%	25%	
Biomass Combustion – Co-firing	4%	8%	12%	
EFOR				
EFORd	4%	8%	12%	
Probability	-25%	50%	25%	
LFG – Reciprocating Engine	3%	8%	12%	
EFOR				
EFORd	3%	7%	11%	
Probability	-25%	50%	25%	
LFG – Combustion Turbine	2%	7%	12%	
EFOR				
EFORd	2%	6%	11%	
Probability	-25%	50%	25%	
Hydroelectric	1%	3%	8%	
EFOR				
EFORd	1%	3%	7%	
Probability	-25%	50%	25%	

⁶ 4 CSR 240-22.040(9)(C); 4 CSR 240-22.040(8)(B)2.; 4 CSR 240-22.040(8)(C)2.

Table 5.B.1 Potential Items for Owner's Costs⁷

Potential Owner's Costs	
Project Development: Site selection study Land purchase/options/rezoning Transmission/gas pipeline rights of way Road modifications/upgrades Demolition (if applicable) Environmental permitting/offsets Public relations/community development Legal assistance Utility Interconnections: Natural gas service (if applicable) Gas system upgrades (if applicable) Electrical transmission Supply water Wastewater/sewer (if applicable) Spare Parts and Plant Equipment: Air quality control systems materials, supplies, and parts Acid gas treating materials, supplies and parts Combustion turbine and steam turbine materials, supplies, and parts HRSG materials, supplies, and parts Gasifier materials, supplies, and parts Balance-of-plant equipment materials, supplies and parts Rolling stock Plant furnishings and supplies Operating spares Owner's Project Management: Preparation of bid documents and selection of contractor(s) and suppliers Provision of project management Performance of engineering due diligence Provision of personnel for site construction Management	Plant Startup/Construction Support: Owner's site mobilization O&M staff training Supply of trained operators to support equipment testing and commissioning Initial test fluids and lubricants Initial inventory of chemicals/reagents Consumables Cost of fuel not recovered in power sales Auxiliary power purchase Construction all-risk insurance Acceptance testing Taxes/Advisory Fees/Legal: Taxes Market and environmental consultants Owner's legal expenses: • Power Purchase Agreement (PPA) • Interconnect agreements • Contracts--procurement & construction • Property transfer Owner's Contingency: Owner's uncertainty and costs pending final negotiation: • Unidentified project scope increases • Unidentified project requirements • Costs pending final agreement (e.g., interconnection contract costs) Financing: Development of financing sufficient to meet project obligations or obtaining alternate sources of funding Financial advisor, lender's legal, market analyst, and engineer Interest during construction Loan administration and commitment fees Debt service reserve fund Miscellaneous: All costs for above-mentioned Contractor-excluded items, if applicable

The technologies evaluated by Black and Veatch estimated generic transmission interconnection costs as a percentage of the EPC cost. Ameren Missouri included an estimate of 2.5 Million for the interconnection cost of pumped hydro at the Church Mountain site. The interconnection cost for solar was assumed to be located at an existing Ameren Missouri power plant site.

⁷ 4 CSR 240-22.040(3); 4 CSR 240-22.040(6)

Compliance References

4 CSR 240-22.040(1)(A)	1, 2
4 CSR 240-22.040(1)(B)	1
4 CSR 240-22.040(1)(C)	1
4 CSR 240-22.040(1)(D)	1
4 CSR 240-22.040(1)(E)	2
4 CSR 240-22.040(1)(F)	3
4 CSR 240-22.040(1)(G)	3
4 CSR 240-22.040(1)(H)	4
4 CSR 240-22.040(1)(I)	1
4 CSR 240-22.040(1)(K)1.	3
4 CSR 240-22.040(1)(K)3.	4
4 CSR 240-22.040(2)	4
4 CSR 240-22.040(2)(C)	4
4 CSR 240-22.040(3)	6
4 CSR 240-22.040(6)	6
4 CSR 240-22.040(8)(B)	2
4 CSR 240-22.040(8)(B)2.	5
4 CSR 240-22.040(8)(C)	3
4 CSR 240-22.040(8)(C)2.	5
4 CSR 240-22.040(9)(A)	4
4 CSR 240-22.040(9)(A)1.	4
4 CSR 240-22.040(9)(A)2.	4
4 CSR 240-22.040(9)(A)3.	4
4 CSR 240-22.040(9)(B)	4
4 CSR 240-22.040(9)(C)	5

6. Transmission and Distribution¹

Highlights

- *Through 2020, Ameren Missouri has a total of 13 transmission projects, at an estimated cost of \$82.6 million, which have been approved by the Midwest ISO Board of Directors.*
- *Ameren Missouri assumed a \$25 billion MISO Multi-Value Project (MVP) system expansion over the next 25 years in addition to the approved reliability and market efficiency projects.*
- *Ameren Missouri has initiated a Voltage Control Pilot Project to enhance operational capabilities and evaluate Conservation Voltage Reduction as an energy and demand conservation measure.*
- *New high-efficiency distribution line transformers may provide cost-effective energy savings beyond new efficiency standards.*
- *Ameren Missouri views the Smart Grid as more of a direction than a destination; this is evidenced by our continuous infusion of technology into the electric grid over the past 30 years – with plenty of work yet to be done.*

Ameren Missouri is continuously maintaining or replacing aging infrastructure in order to provide safe and reliable service. Rapid growth during the 1960s and 70s due to a housing boom and the advent of air conditioning resulted in a replacement of the previous vintage infrastructure and an even larger new system. As growth has slowed over time the infrastructure has not experienced appropriate turnover. This lack of asset turnover means our existing grid is heavily populated with 40-50 year old equipment that is at risk for failure, obsolete, and inefficient compared to modern equipment. Ameren Missouri has proactively begun to address this issue, and plans to make significant investments to replace its aging grid infrastructure to improve overall system reliability and efficiency. In doing so, Ameren Missouri will incorporate cost-effective advanced technologies on an opportunistic basis that provide enhanced energy services and mitigate future obsolescence.

Ameren Missouri has evaluated a range of transmission and distribution options as part of a 2009 End-to-End Efficiency Study² performed with the assistance of EPRI. The study helped identify some promising opportunities including Conservation Voltage Reduction, Reactive Power Optimization, and High-Efficiency Transformers. In fact, Ameren Missouri has initiated a Voltage Control Pilot Project to enhance operational

¹ 4 CSR 240-22.040(7)

² EO-2007-0409 – Stipulation and Agreement #16; EO-2007-0409 – Stipulation and Agreement #17;

4 CSR 240-22.040(7)

capabilities and evaluate Conservation Voltage Reduction as an energy and demand conservation measure. Many of the conclusions from the EPRI study were based on generic data and therefore need further analysis. However, Ameren Missouri has included 100 MW of peak-time voltage reduction in its capacity planning based on its long history of experimentation with this resource.

Ameren Missouri has a total of 13 projects which have been approved by the Midwest ISO Board of Directors. Nine of these projects are Baseline Reliability Projects which are required to meet NERC TPL reliability standards and have an estimated cost of \$58.5 Million. The remaining four projects are needed for a variety of other reasons including generator interconnections, providing supply to new load connections, etc., and have an estimated cost of \$24.1 Million. Ameren Missouri also has three projects, totaling over \$320 Million, in the Candidate Multi-Value Projects (MVP) list and which would be allocated across MISO according to the approved cost allocation method recently approved by FERC. Ameren Missouri assumed there would be a \$25 billion MVP build-out over the next 25 years across the entire Midwest ISO territory, which would effectively eliminate any transmission barriers to wind resources. It is expected that approximately 8% of those costs would be passed on to Ameren Missouri's customers.

6.1 Transmission

6.1.1 Existing System

Ameren Missouri owns and operates a 2,944 mile transmission system that operates at voltages from 345 kV to 138 kV. The system is composed of the following equipment:

- 1,284 miles of 138 kV transmission circuits
- 717 miles of 161 kV transmission circuits
- 943 miles of 345 kV transmission circuits
- 24 extra high voltage substations with a maximum voltage of 345 kV
- 26 substations with a maximum voltage of 161 kV
- 34 substations with a maximum voltage of 138 kV

The system has been developed over many decades to provide reliable and economical transmission of electrical energy from power plants to where our customers work and live.

6.1.2 Regional Transmission Organization Planning

Since 2004, Ameren Missouri has been a member of the Midwest Independent Transmission System Operator, or Midwest ISO, a Regional Transmission Operator (RTO). The Midwest ISO was approved as the nation's first RTO in 2001 and was created as an independent, nonprofit organization that supports the delivery of

wholesale electricity in 15 U.S. states and the Canadian province of Manitoba across nearly 94,000 miles of interconnected high voltage power lines. A key responsibility of the Midwest ISO is the development of the annual Midwest ISO Transmission Expansion Plan (MTEP). The MTEP identifies solutions to meet regional transmission needs and to create value opportunities via the implementation of a comprehensive planning approach. The MTEP development process also serves as a mechanism to evaluate and help coordinate the transmission plans developed by Midwest ISO Transmission Owners. This evaluation insures that transmission plans developed by the Transmission Owners are coordinated across the Midwest ISO territory and identify potential alternative solutions that could address multiple system needs. The result of the MTEP process is the compilation of transmission projects that are needed to address system reliability requirements and/or provide specific system benefits as delineated in the Midwest ISO Tariff. These projects are listed and described in the MTEP Appendix A.

The projects in MTEP Appendix A have been reviewed and approved by the Midwest ISO Board of Directors (BOD). Each MTEP document is identified by the year in which it was completed. The MTEP10 document is the culmination of more than 18 months of collaboration between Midwest ISO planning staff and stakeholders. Each MTEP cycle focuses upon identifying issues and opportunities, developing alternatives for consideration, and evaluating those options to determine effective solutions. The primary purpose of the MTEP process is to identify transmission projects that:

- Ensure the reliability of the transmission system.
- Provide economic benefits such as increased market efficiency and resultant lower energy cost.
- Facilitate public policy objectives such as integrating renewable energy.
- Address other issues or goals identified through the stakeholder process.

The MTEP10 Appendix A contains 230 new approved projects located throughout the Midwest ISO territory representing an incremental \$1.2 billion in transmission infrastructure investment through 2020. These projects fall into the following five (5) categories:

- **Multi-Value Projects (One [1] project, \$510.0 million):** Projects providing regional public policy and/or economic benefits. This project was reviewed and approved by the Midwest ISO Board of Directors on August 19, 2010.
- **Baseline Reliability Projects (37 projects, \$94.3 million):** Projects required to meet North American Electric Reliability Corporation (NERC) reliability standards. These standards impact facilities of a voltage greater than 100 kV and represent the minimum standard applied across the Midwest ISO's footprint.

- **Generator Interconnection Projects (Six [6] projects, \$6.85 million):** Projects required to reliably connect new generation to the transmission grid.
- **Transmission Service Delivery Projects (Two [2] projects, \$3.9 million):** Projects required to satisfy a Transmission Service Request. The costs of these projects are always direct assigned to the requestor.
- **Other Projects (184 projects, \$569.9 million):** A wide range of projects, such as those designed to provide local economic or similar benefit but not meeting the threshold requirements for qualification as Regionally Beneficial Project/Market Efficiency Projects, and projects required to support the lower voltage (less than 100 kV) transmission system.

With the addition of the recently approved transmission projects contained in the MTEP10 Appendix A, the total number of approved projects in the Midwest ISO territory is now 613 which represents an estimated investment of \$4.7 billion through 2020. When completed, the projects will result in approximately 4,200 miles of new or upgraded transmission lines throughout the Midwest ISO territory.

6.1.3 Ameren Missouri Transmission Planning

Ameren Missouri's transmission strategy is centered upon meeting the changing requirements of our customers and the evolving utility industry. Successful implementation requires our involvement in a multitude of planning activities including:

- Local area planning considering load growth and system development requirements,
- Participation in NERC reliability standards development,
- Participation in SERC regional planning activities,
- Participation in EIPC Eastern Interconnection planning activities,
- Participation in regional generation interconnection evaluations
- Coordination with the Midwest ISO to improve overall regional operations,
- Participation in the Midwest ISO MTEP development process, and
- Engagement with the Midwest ISO on Tariff issues and Business Practice Manual issues.

Our goal with this high level of involvement in these many transmission planning processes is to maintain a reliable and efficient transmission system while meeting the current and future needs of our customers.

Ameren Missouri routinely performs rigorous analyses of the Ameren Missouri system throughout a one- to ten-year planning horizon. These studies consider the effects of system load growth, the adequacy of the supply to new and existing substations to meet local load growth, the selection of sites for new generation resources, the changing

regional use of the bulk electric system (BES) and the resulting impacts on the reliability of the Ameren Missouri transmission system. In the event that these studies forecast reduced reliability, additional studies evaluating all practical alternatives are performed to determine what, where and when system upgrades are required. These proposed solutions include applicable new technologies, e.g. Flexible AC Transmission System (FACTS) devices, high-temperature operation conductor, etc., as well as more traditional planning solutions. The total cost for maintaining system reliability is considered for the expansion options.

Ameren Missouri is an active participant in the Midwest ISO annual MTEP development process. We work with the Midwest ISO to coordinate and pursue activities associated with the planning, operation, and maintenance of the transmission system. Participation in the Midwest ISO MTEP process is the method by which Ameren Missouri's local transmission plan is "rolled-up" as a portion of the annual MTEP document and projects included in MTEP Appendix A. The MTEP process provides the opportunity to evaluate regional solutions that may more cost effectively resolve multiple local issues. Through these activities with the Midwest ISO, adjacent Transmission Owners, and stakeholders, Ameren Missouri works to provide a reliable system throughout the Midwest region and to ensure that opportunities for system expansion make sense and would provide the required system benefits while seeking a balance between regional and Ameren Missouri goals.

Ameren Missouri also participates in regional generation interconnection studies for proposed generation interconnections inside and outside of the Ameren Missouri footprint. Ameren Missouri responds to requests for proposals from Midwest ISO and performs studies of proposed generation interconnections to the Ameren Missouri system or alternatively, Ameren Missouri participates in the ad hoc stakeholder groups that oversee these studies. Participation in these activities ensures that the studies are performed on a consistent basis and that the proposed connections are integrated into the Ameren Missouri system to maintain system reliability. Powerflow, short-circuit, and stability analyses are performed to evaluate the system impacts of the requested interconnections. If system deficiencies are identified in the connection and system impact studies, additional studies are performed to refine the limitations and develop alternative solutions.

Ameren MTEP10 Projects (Appendix A)

Ameren Missouri has a total of 13 projects (six new projects in MTEP10 Appendix A) which have been approved by the Midwest ISO Board of Directors. These 13 projects have a total estimated cost of \$82.6 Million. Nine of these projects are Baseline Reliability Projects which are required to meet NERC TPL reliability standards and have a total estimated cost of \$58.5 Million. The remaining four projects are needed for a

variety of other reasons including generator interconnections, providing supply to new load connections, etc., and have a total estimated cost of \$24.1 Million. Major projects include a new bulk substation and 161 kV supplies in the Troy area, addition of a second 345/138 kV transformer at Gray Summit Substation and reconductoring portions of the Sioux-Huster 138 kV lines. The complete Midwest ISO MTEP10 document and the list of Appendix A projects that have been approved by the Midwest ISO Board of Directors are available on MISO's website: www.MidwestISO.org. For convenience, the full MTEP10 report is contained in the electronic workpapers as "MISO MTEP10.pdf".

Ameren MVP Initiatives

Ameren Missouri is an active participant in the Midwest ISO initiative to identify major transmission projects which provide broad benefits across the Midwest ISO territory. The projects currently being analyzed are expected to be classified as Multi-Value Projects (MVPs). In order to be classified as an MVP, a project must meet the following criteria as defined in the Midwest ISO Tariff, Attachment FF:

A Multi Value Project must meet one of the three criteria outlined below:

- a. Criterion 1. A Multi Value Project must be developed through the transmission expansion planning process for the purpose of enabling the Transmission System to reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirements that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade.
- b. Criterion 2. A Multi Value Project must provide multiple types of economic value across multiple pricing zones with a Total MVP Benefit-to-Cost ratio of 1.0 or higher where the Total MVP Benefit-to-Cost ratio is described in Section II.C.6 of this Attachment FF. The reduction of production costs and the associated reduction of LMPs resulting from a transmission congestion relief project are not additive and are considered a single type of economic value.
- c. Criterion 3. A Multi Value Project must address at least one Transmission Issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic-based Transmission Issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in

excess of the total project costs based on the definition of financial benefits and Project Costs provided in Section II.C.6 of Attachment FF.

To be classified as an MVP a project must meet additional specific criteria that are also contained in Attachment FF of the Midwest ISO Tariff.

The Midwest ISO and stakeholders are currently analyzing an initial set of transmission projects that have been identified as the Candidate MVP Portfolio. At this time the following transmission projects are included in the Candidate MVP Portfolio that would impact the Ameren Missouri transmission system

- Thomas Hill – West Adair – Ottumwa 345 kV line (105 miles): Expected to be in-service by June 1, 2016 with a preliminary cost estimate of \$195 MM. The preliminary cost estimate includes both the Missouri and Iowa portions of the line.
- West Adair – Palmyra Tap 345 kV line: Expected to be in service by June 1, 2018 with a preliminary cost estimate of \$100 MM.
- Palmyra Tap – Quincy IL 345 kV line: Expected to be in service by June 1, 2018 with a preliminary cost estimate of \$27 MM. The preliminary cost estimate includes both the Missouri and Illinois portions of the line.

These projects will improve the efficiency of the transmission system by reducing losses, enhancing delivery of existing generation, and reducing congestion both within Missouri and between Missouri and the rest of the Midwest ISO. The analysis of these projects is expected to be completed during 2011 with the results documented in the Midwest ISO MTEP11 report.

6.1.4 Cost Allocation Assumptions for Modeling³

For modeling purposes, Ameren Missouri assumed the construction of projects necessary for the continued reliable and efficient operation of the transmission system. This included the assumption that the Midwest ISO analysis would determine that the full set of Candidate MVP Portfolio projects meet the criteria to be classified as MVP projects and subsequently would be approved by the Midwest ISO Board of Directors. The costs of MVPs would be allocated per the Midwest ISO Tariff and not be assigned to specific generation projects. Therefore, as the transmission interconnection costs of new generation facilities have been estimated, only the direct transmission interconnection costs have been included by assuming any relevant transmission backbone will be part of the MVPs.

Ameren Missouri assumed there would be a \$25 billion MVP build-out over the next 25 years across the entire Midwest ISO territory with the investments hitting customer rates in \$5 billion increments every 5 years. Adjusting for known changes in MISO

³ 4 CSR 240-22.040(6); 4 CSR 240-22.040(3); EO-2007-0409 – Stipulation and Agreement #14

membership, Ameren Missouri's load is 7.85% of MISO load, and Ameren Missouri's generation is 8.6% of MISO generation. It is also assumed 10% of costs will be assigned to generators and 90% of costs will be assigned to load. Overall, Ameren Missouri expects approximately 8% of the MVP costs to be assigned to its customers. For modeling revenue requirement impacts a 16% fixed charge rate was used.

It is noteworthy that the IRP analysis was completed before FERC approved MISO's cost allocation method for the MVP projects in December 2010. The FERC approved method assigns 100% of the costs to the load. In the IRP analysis only 10% was allocated to the generators, and since Ameren Missouri's load and generation share of MISO are similar, the change in method would slightly reduce the amount allocated to Ameren Missouri compared to the assumptions at the time of the IRP analysis. Furthermore, these costs are common to all resource plans and therefore do not affect relative plan performance.

6.2 Distribution

6.2.1 Existing System

Ameren Missouri delivers electricity to approximately 1.2 million customers across central and eastern Missouri, including the greater St. Louis area, through distribution system power lines that operate at voltage levels ranging from 2,400 volts (V) through 69,000 V. Ameren Missouri has 33,000 circuit miles of electric distribution lines, which move electricity into the 63 counties and more than 500 communities where businesses operate and people live.

Approximately 70% of Ameren Missouri's distribution system operates at 12,470 V, 11% operates at 34,500 V and 12% operates at 4,160 V, with the remainder operating at other levels. (See graphic depiction of the Distribution System in Figure 6.1 for further detail.)

Figure 6.1



Here's how the power flows from a power plant to an electric customer:

- ① Electricity travels from the power plant over high-voltage transmission lines.
- ② At a substation, the electricity's voltage is lowered so that it can travel over the distribution system.
- ③ Main distribution power lines, typically 3-phase circuits, bring electricity into communities.
- ④ Local distribution power lines serve neighborhoods and individual customers.
- ⑤ Service drops carry electricity from pole-mounted or pad-mounted transformers - which lowers the voltage again - to customer premises.

Much of the distribution system in rural areas is supplied from a single substation source (#2 in Figure 6.1 above) that does not connect to other substation sources. Often, rural areas are supplied by long power lines that may serve several isolated communities. To counteract voltage drop and maintain proper voltage levels along lengthy circuits, the company installs capacitors or voltage regulators.

The distribution system in urban areas typically is interconnected, with customers able to receive power from more than one substation source (#2 in graphic above). At any given point in time each customer is served by a single power source, but by opening and closing switches, the company can re-configure the interconnected system to maintain service to customers via alternate sources and routes when portions must be de-energized to perform maintenance or complete repairs. Capacitors are generally used to maintain adequate voltage levels and power factor.

Finally, a portion of the distribution system is networked, which means customers are continuously connected to more than one source. Examples include the 120/208 V underground distribution network in downtown St. Louis and the 69,000 V network that supplies communities throughout central Missouri, including Jefferson City, Kirksville, Moberly and Montgomery City.

Ameren Missouri's distribution system includes both overhead and underground power lines at the low and medium voltage distribution levels. Underground lines (22% of the total) are more aesthetically pleasing and less vulnerable to weather-caused damage, but they take longer to repair upon failure and are significantly more expensive to install and replace.

6.2.2 System Inspection

Ameren Missouri assesses the age and condition of distribution system equipment with regular inspection, testing and equipment replacement programs, as described below.

Circuit and Device Inspections

Ameren Missouri inspects all distribution circuits (4,160 V to 69,000 V) at least every six years, in compliance with Missouri PSC Rule 4 CSR 240-23.020, to protect public and worker safety and to proactively address problems that could diminish system reliability. The program includes follow-up actions required to address noted deficiencies. Inspections include all overhead and underground hardware, equipment and attachments, including poles. Wooden poles are treated every 12 years as appropriate for purposes of life extension. Inspectors may also measure impedance of the grounding system. Through this program, Ameren Missouri also inspects all line capacitors, reclosers, and regulators on an annual basis. Any inoperable cells are repaired or replaced, helping to ensure optimal power factor system-wide. Ameren

Missouri also replaces a number of transformers each year with higher efficiency units when corrosion, oil leaks or other visually detectable issues occur.

Underground Cable Replacements

Sections of single phase or three phase direct buried cable are replaced when the failure history of the cable or cable section is excessive. Once a cable qualifies for replacement, a local engineer studies its performance, as well as the performance of the lateral on the other side of the “normal open” if it is looped, in order to determine how much cable (if any) will be replaced.

Cables that have failed but do not satisfy any of the criteria also may be replaced based on local engineering judgment, with Ameren Missouri personnel making the case for replacement based on field observations and other necessary investigations.

Substation Asset Management

Ameren Missouri schedules substation maintenance to maximize reliability of equipment, and selectively performs various diagnostic tests to obtain meaningful data to predict and prevent failures. Many tests, such as infra-red scanning to detect abnormal equipment heating, can be performed with the equipment in-service. Corrective maintenance is scheduled largely on the basis of diagnostic data, with the intent of restoring equipment to full functionality. When it is no longer practical to make repairs, old equipment is replaced with new, with an emphasis on efficiency and reduction of losses.

Conversion of Dusk-to-Dawn and Municipal Street Lighting

Ameren Missouri has replaced all mercury vapor lights with more efficient high-pressure sodium lights (or metal halide for color sensitive applications). The company continually monitors the development of more efficient lighting technology and is currently participating in an EPRI test of twelve LED luminaries in St. Louis County. More discussion of this pilot program can be found in Chapter 7 (Section 7.6.5).

6.2.3 System Planning

Ameren Missouri assesses system capacity, efficiency and losses through seasonal distribution system planning studies.

Annual Load Analysis and System Planning Process

Ameren Missouri records summer and winter peak load conditions (power, power factor, phase balance and voltage levels) at bulk and distribution substations. Distribution loads are temperature-corrected to represent 1-in-10 year maximum values using multipliers derived from statistical analyses of historic load data for several types of area load characteristics. Temperature adjustments for bulk substations are derived from historical temperature vs. loading profile curves for each particular bulk substation.

Engineers also calculate bulk substation loads using a power flow computer model that simulates the electric power delivery system. Using temperature-corrected distribution substation loads and current equipment ratings as inputs, the software calculates bulk substation loads. These are compared to temperature-corrected values and used to evaluate what, if any, diversity factors apply at each bulk substation.

After verifying the validity of the system model, engineers conduct seasonal planning studies of winter and summer peak conditions, evaluating worst case single-contingency failure scenarios for all bulk substations, 34,500 V and 69,000 V circuits, distribution substations, and distribution circuits. These studies pinpoint system limitations and enable engineers to identify upgrades required to maintain adequate system capacity. The evaluation of distribution system losses and maintenance of adequate system voltage levels are included in these analyses.

Planning system upgrades to withstand single-contingency outage conditions ensures that load levels will remain within circuit capabilities for such events. Under normal conditions (the majority of the time) individual circuit elements operate at lower load levels with correspondingly lower losses.

An integral part of the entire load analysis process is the establishment of equipment ratings and/or loading limits. Ameren Missouri evaluates transformer and conductor losses as part of the methodology used to establish distribution equipment ratings.

Distribution System Engineering Analyses

The Transformer Load Management (TLM) System relates customers to the distribution transformers serving them, allowing Ameren Missouri to predict transformer peak demand and apparent power from the customers' total monthly energy usages. Ameren Missouri uses this information to analyze distribution circuits and to reduce distribution losses through the more efficient loading of transformers. Additionally, customer meters are automatically read during peak load periods to confirm the transformer peak demands calculated with the TLM system.

EPRI's Distribution Engineering Workstation (DEW) software and Siemens PTI PSS/E software are used to analyze distribution circuits, ensuring reliable, safe, and efficient operation of the distribution system. DEW or PSS/E is used for: load estimation, power flow analysis, protective device coordination, fault current calculation, voltage flicker, phase balancing, and capacitor placement. Both software systems allow engineers to analyze existing, alternate, or proposed configurations for over/under voltages/currents, line losses, appropriate conductor sizing, and optimal capacitor placement.

SCADA (Supervisory Control and Data Acquisition) is used to remotely monitor and control the electric distribution system. Engineers use SCADA data to ensure that

system models properly reflect real distribution system conditions, therefore enabling better planning of future system development.

Capital Project Evaluation

Ameren Missouri assesses the feasibility and cost effectiveness of potential system upgrades or expansion projects on an ongoing basis. Although potential capital projects are identified by various operating, engineering and planning personnel, all bulk substation, power line, and distribution substation projects are reviewed by Distribution System Planning prior to consideration for funding.

All projects are compared using the Integrated Spending Prioritization (ISP) tool, an application that evaluates both the costs and benefits of each potential project in order to establish funding priorities. Key to this evaluation is a reliability-based prioritization metric called the Service Availability Cost Factor (SACF) - a calculated index that facilitates ranking projects on a common cost-benefit basis. In its simplest form, SACF represents the cost per unit risk where risk is measured as customer load in kVA multiplied by hours of outage. Cost per kVA-hr saved, then, represents the investment required to avoid an outage to one kVA of customer load for one hour. By giving preference to projects with the lowest SACF scores, Ameren Missouri ensures that system reliability will be enhanced as fully as possible through proper prioritization of capital investments.

6.2.4 System Efficiency

Ameren Missouri regularly pursues opportunities to improve distribution system efficiency through ongoing activities and projects, including those listed below:

Periodic System Loss Study

Ameren Missouri evaluates the efficiency of its overall electric delivery system on a periodic basis by performing a comprehensive loss study. Losses in each portion of the system are calculated under peak load conditions using the computer software noted previously. Loss data from these evaluations are used in ongoing system planning activities and as supporting information for Rate Case Filings.

System Upgrade and Expansion Projects

By their nature, many types of energy delivery upgrade and expansion projects improve system efficiency by reducing load current, I^2R losses, or both. Examples of such projects include:

- Constructing new circuits or rebuilding existing circuits that make use of higher operating voltages, as in the conversion of power lines from 4 kV to 12 kV or the migration toward 138kV-fed distribution substations
- Constructing new circuits or rebuilding existing circuits with larger conductors

- Reconnecting single phase loads on three phase circuits to achieve balanced system phase currents
- Upgrading existing substations or strategically placing new substations to serve areas with increasing load density; and
- Reconfiguring distribution feeders as appropriate when connecting new customers

Reactive Power (VAR) Optimization

Customer loads consume real power (measured in watts), however AC power systems also require reactive power (measured in volt-amperes-reactive, or VARs) to deliver energy. Delivering VARs consumes distribution circuit capacity and can create undesirable levels of voltage drop. Ameren Missouri installs capacitor banks to maintain overall power factor near unity, thereby releasing as much system capacity as practical. Maintaining a power factor near unity reduces the current flows through the system that are necessary to satisfy its real power requirements. This in turn lowers line losses (I^2R losses) and reduces conductor heating, ultimately helping to prolong equipment life.

Because the amount of reactive power that customers need varies with load, a controlled but variable source of VARs enables optimal system performance. Ameren Missouri employs automatic and remotely controlled capacitor banks to stabilize system voltage as loads are cycled on and off. As recommended in the 2009 Ameren Missouri End-to-End Efficiency Study, performed with assistance from EPRI, Ameren Missouri plans to increase its focus on optimizing reactive power flow in the system. The company has budgeted to install a fleet of new capacitor bank controls for deployment from 2011 through 2015. These new controls will replace aging equipment and improve system performance, power factor and distribution system efficiency.

Volt/VAR Optimization Supporting Conservation Voltage Reduction

Because customer electric demand and energy consumption vary in proportion to the supply voltage, distribution system voltage adjustments (narrowing and lowering voltage ranges) can reduce total power consumption.

As noted in the 2009 Ameren Missouri End-to-End Efficiency Study conducted by EPRI, the results of industry Conservation Voltage Reduction (CVR) studies indicate that for every 1% reduction in delivered utility voltage, customer energy consumption may drop as much as 0.6 - 1.0%. Recognizing that CVR should be limited by what can be tolerated operationally by customers, and beyond that has to be limited by the minimum acceptable voltage level allowed by Missouri PSC standards, Ameren Missouri is interested in some controlled experimentation with CVR on its distribution system.

Ameren Missouri has initiated a Voltage Control Pilot Project to enhance operational capabilities and evaluate CVR on selected distribution power lines. Most circuits to be studied are part of a distribution automation project in St. Louis County; others are located in a more rural setting northwest of the metropolitan area. Design and construction of the pilot project are planned for 2011, with operational testing planned for late 2011 and 2012. Potential distribution energy savings, and the costs to achieve them, will be determined upon the project's conclusion.

Loss-Evaluated Distribution Transformer Purchasing

Ameren Corporation currently purchases transformers based on Total Cost of Ownership (TCO), including acquisition cost plus the evaluated cost of no-load and load losses, capitalized over a 30-year life. By purchasing high-efficiency distribution transformers that meet the US Department of Energy efficiency requirements, Ameren will gradually reduce total circuit losses in a cost-effective manner. Ameren conservatively projects an annual demand savings from replacing ~17,000 transformers yearly in Missouri and Illinois of 0.22 MW, and an annual energy savings of 1,634 MW-hrs.

Ameren evaluates the option to purchase high-efficiency, amorphous core transformers as they become available in volumes required. Although amorphous core transformers presently carry an additional purchase premium, the corresponding reduction of no-load losses can lead to a favorable TCO and an improvement in system efficiency to the long-term advantage of rate payers.

6.2.5 Peak Demand Reduction via Voltage Control

For over 20 years, Ameren Missouri has had the ability to reduce demand at selected distribution substations by reducing load tap changer (LTC) voltage setpoints at the time of peak system demand. This is a short-term strategy that has been limited to emergency situations.

As part of Ameren Missouri's alternative resource plan, the company includes 100 MW of demand reduction at the time of system peak. The 100 MW represents current system capabilities and therefore does not include any potential effects of Conservation Voltage Reduction evaluated earlier in this chapter.

Estimating demand reduction due to voltage control begins with identifying substations with appropriate LTC equipment. Ameren Missouri has identified 260 substations capable of implementing voltage control. The magnitude of potential demand reduction has been estimated based on substation demand data gathered from July 2008 through June 2009, a test year used to support weather normalization modeling.

It is estimated that 70% of the summer distribution system peak demand, or approximately 5,400 MW, is served by substations with voltage control capability. Although higher levels of voltage reduction are possible, this study assumed voltage reduction would be limited to 2.5%. Based on Ameren Missouri experience, load decreases by approximately 0.84% for every 1% reduction in voltage. Furthermore, experience indicates not all LTC equipment responds when signaled to reduce voltage. It is assumed that 90% of the equipment will respond properly. On this basis, Ameren Missouri can achieve approximately 100MW of demand reduction via voltage control at the time of system peak.

6.2.6 Distributed Generation

Ameren Missouri does have some interest in distributed generation (DG) as a means of deferring distribution system expansion projects. Potential projects can be analyzed on a case-by-case basis; however, the scope of potential candidates tends to be small. Furthermore, other factors that tend to exacerbate potential DG installations include noise and/or emissions ordinances, operational complexities associated with fuel availability, equipment maintenance, etc., and the fact that traditional system expansion projects usually provide secondary benefits like improving reliability.

Typically customer-owned generation is non-dispatchable; therefore this type of resource is not included when performing load analysis and system improvement justifications. Chapter 7 explores distributed generation as a demand-side resource.

6.3 Smart Grid

6.3.1 Smart Grid Overview

There have been many technological, operational and societal benefits identified in association with the US Department of Energy's vision for the Smart Grid. Ameren Missouri's Smart Grid vision focuses on the continued pursuit of service reliability, operating efficiency, and asset optimization, and on building a secure, robust energy delivery infrastructure as a means of enabling other Smart Grid elements. Among these elements are emerging technologies owned and operated by customers who are motivated by the prospect of becoming more active participants in energy-related decisions.

Ameren Missouri views the Smart Grid as the infusion of technology – communications technology, automation technology, and end-device intelligence – into the otherwise passive system of poles, wires, cables, transformers, switches and meters comprising the electric infrastructure. From a practical standpoint, capabilities like communicating with end devices, controlling them remotely, configuring them to operate automatically, receiving reports back on what they did, and the central control and back office systems

necessary to integrate and support these functions, all represent features of an intelligent grid.

Ameren Missouri views the Smart Grid as more of a direction than a destination. Given the digital nature of the technology being referenced by the term and the frequency with which it turns over relative to the more robust hardware it attempts to automate, the Smart Grid will never represent a discrete state of existence that, once arrived at, signals the end of the effort. Simply put – in the same way that few people will ever have their “last” cell phone or their “last” personal computer, the electric grid will likely never achieve what can be considered a “final state” of automation or intelligence.

Ameren Missouri’s current activities in electric infrastructure technology are driven by deliberate and intended benefits associated with its adoption of the Smart Grid. These intended outcomes are summarized below:

Reliability Improvement – Deploy smart technologies across the energy delivery infrastructure in order to improve electric service reliability for Missouri customers.

Efficiency, Optimization and Integration – Improve the operating efficiency and asset optimization of the energy delivery infrastructure and further integrate Ameren’s existing Smart Grid applications, allowing for the flexibility, scalability, and extensibility of these and future applications.

Customer Enablement and Use of Technology – Provide the necessary resources to both prepare the electric grid for emerging customer technologies and enable motivated electric customers in Missouri to make use of those technologies and become more active participants in energy decisions.

Ameren Missouri sees its communication role as one of leading its employees, customers, regulators, and other stakeholders to a greater understanding of Smart Grid concepts, applications, and potential benefits, as well as Ameren Missouri’s specific plans for the future. Internally, Ameren Missouri fosters an environment of continuous learning for leaders and subject matter experts around Smart Grid topics through its participation in pilot installations and research projects, its participation with other utilities and industry groups on the development of Smart Grid concepts and standards, and the engagement of external consultants and industry experts. Additionally, there will be opportunities to partner with property developers and large customers in active demonstrations that showcase Ameren Missouri’s Smart Grid applications.

6.3.2 Ameren Missouri's Smart Grid Plan

6.3.2.1 Reliability Improvement

Automated Switching Applications

Ameren Missouri's strategy for automating subtransmission circuits (34kV and 69kV) is to install smart switching devices in order to limit the load dropped due to a single line contingency to 10 MVA or less in those cases where the existing circuit topology supports the restoration of unfaulted line sections to an alternate or paralleled source. Up to 200 automated switches could be required in addition to the 220 already in service to fully deploy on this strategy over the next 10-15 years.

Ameren Missouri's strategy for automating 12kV distribution circuits is to install smart switching devices at 12kV (at least one bisecting the feeder backbone and at least one tying it to a different feeder) in order to limit the load dropped due to a single line contingency to roughly half the feeder's peak load or less in those cases where the existing circuit topology supports the restoration of unfaulted line sections to a different feeder. Up to 1,600 automated switches could be required in addition to the 160 already in service to fully deploy on this strategy over the next 20-25 years.

Ameren Missouri plans to deploy on these smart switching strategies annually by circuit, substation, or group of adjacent substations as appropriate, according to the greatest combined customer density and potential reliability improvement for the cost. Substation and circuit candidates for switching solutions are identified through the standard annual contingency analysis studies conducted, as well as through periodic reliability reports of worst-performing feeders, worst performing high customer-density substations, etc.

Smart Substation Technologies

For many years Ameren Missouri has been building substations that are considered "smart" by today's standards. As a means of ushering in the next generation of substation intelligence in the industry, Ameren Missouri is incorporating combinations of winding temperature sensing, bushing power factor monitoring, water and dissolved gas content monitoring, and multi-function temperature sensing into the standard design of capital substation projects. These projects include the construction or re-build of entire substations as well as the installation or replacement of substation transformers. Additionally, mobile substation transformer purchases going forward will feature a combination of these types of sensors.

Industry data indicates that over the long term, the capture and trending of substation transformer diagnostic sensor data can reduce substation outage events due to unforeseen transformer failures and extend the average operating lives of these large

assets. The premium for the sensing technology involved is less than 5% over all construction scenarios. Ameren Missouri plans to install this sensor technology on substation transformers over time as an integral part of its capital substation projects going forward, including those undertaken for reasons of load growth, reliability upgrade, or condition-based maintenance.

Ameren Missouri's strategy for substation relaying is to upgrade up to ten transmission terminals (above 100kV) annually to microprocessor-based relaying from the existing electromechanical and solid state technologies, based on a current population of 350 terminals and an estimated protection system design life of 30 to 40 years. Ameren Missouri also plans to upgrade up to four subtransmission network terminals (69kV) annually based on a current population of 90 terminals.

A single microprocessor relay package combines the functionalities of several pieces of legacy equipment, resulting in fewer points of failure and less control wiring. Self-diagnostic checks remotely alert personnel of their own operating condition, reducing the need for periodic maintenance and allowing for intervention before failure or misoperation occurs. Trip check maintenance is also greatly simplified, further reducing periodic maintenance.

The current plan is to have electromechanical and solid state relays extinct from Ameren Missouri's transmission system in the next 10-15 years. Ameren Missouri plans to convert as many of these as possible in association with other substation expansions, line maintenance activities and remote terminal upgrades. The remainder will be converted programmatically based on obsolescence, with priorities placed on relays found inoperable during routine maintenance followed by those with histories of uncorrectable misoperations.

6.3.2.2 Efficiency, Optimization, and Integration

Multi-Layered Network Architecture

Currently several isolated and overlapping networks are operating today in support of AMR meters, radio-controlled line capacitors, substation SCADA and automated switching, none of which is sufficient for the long-term expansion and widespread use of intelligent end devices. It's anticipated that more capacity will be required for ultimate end device populations in the tens of thousands, and more speed could be required to support large file transfers from remote diagnostic sensors in substations.

In response to this Ameren Missouri has developed and is deploying a multi-layered network architecture intended to support existing smart applications and enable future applications – a Wide Area Network (WAN) backbone for backhauling large amounts of field application data, Local Area Networks (LANs) for aggregating intelligent end device

data (typically at substation locations), and Field Area Networks (FANs) for supporting communication with field end-devices beyond and downstream from the substation.

Ameren Missouri is developing a WAN that leverages various industry-proven transport systems such as fiber, digital microwave, and common carrier leased services, and likely features a mix of private and non-shared public infrastructure of either a wired or wireless nature. WAN infrastructure additions over time will focus on the connection of substations and other key network entry points, the delivery of information to the control center(s), and the application of necessary security layers throughout the network architecture.

Ameren Missouri is deploying LAN technology over time at substations as their specific locations are identified as effective aggregation points for planned feeder deployments of intelligent end devices like automated line switches, capacitors and regulators. Since these devices are being deployed on the distribution system by circuit or substation, the already owned or leased substation site becomes the preferred choice for this aggregation. Targeting these deployments at “smart” substation sites also allows for communications consolidation and maximizing the impact of the LAN infrastructure investment.

In some areas of the Ameren Missouri service territory the FAN will feature a radio frequency (RF) mesh network that is both self-organizing and self-optimizing, dynamically routing data communications amongst a diverse set of paths that wirelessly interconnect multiple end devices. In other areas, the FAN will feature a more traditional point-to-multipoint RF network or a cellular-based alternative, depending on the application and its inherent reliability and latency requirements. Ameren Missouri plans to adopt the use of intelligent end devices with open architectures as endorsed by National Institute of Science and Technology (NIST) standards, regardless of the smart applications involved and the other technology choices made.

Advanced Distribution Management System (ADMS)

Ameren Missouri is implementing an Advanced Distribution Management System (ADMS) as a means of providing an integrated suite of software applications with which to manage the electric distribution system. It is a highly integrated system of applications that provides distribution system operators a common user interface with which to monitor and control the distribution system on a daily basis. It not only replaces existing applications like outage management, switching orders, and Supervisory Control and Data Acquisition (SCADA), it features new applications such as dynamic circuit modeling, switching and restoration simulations, and a distribution system dashboard.

ADMS is foundational to future Ameren Missouri Smart Grid planning since it enables advanced applications that rely on the integration of functions formerly separate and distinct. In addition, ADMS allows for growth and scalability that is not feasible on the current platforms in use and provides the flexibility to add and integrate future applications. Current Ameren Missouri plans call for the ADMS platform to be implemented by the end of 2012.

Supervisory Control and Data Acquisition (SCADA)

Ameren Missouri's strategy for substation supervisory control and data acquisition is to programmatically introduce remote load monitoring at existing substations lacking such capability, for purposes of improving daily operations and facilitating the long-term planning of substation assets. Remote outage detection and supervisory control features will be introduced at existing substations lacking such capability on an opportunistic basis in association with other capital projects.

Ameren Missouri's 30+ years of experience in this area has shown that continuously updated load information on substation components can defer or eliminate previously justified capital projects, quickly identifies unforeseen overloads, releases capacity by allowing for daily operation closer to margin, and greatly enhances outage restoration activities. Remote metering also enables automatic transfer capability in smart switching applications and enables feeder level optimization via phase balancing and the operation of line capacitors. Supervisory control of switching devices further enhances operations by allowing for real-time outage notification and immediate intervention by dispatchers in restoration scenarios.

Of Ameren Missouri's 525 distribution substations, there are approximately 190 without remote metering capability. Ameren Missouri's plan is to upgrade a prescribed number of these substations annually on a programmed basis according to the preferences of operating and circuit planning entities, and align these upgrades as appropriate with smart switching and smart capacitor deployments that are planned on associated feeders.

There are approximately 250 Ameren Missouri distribution substations without outage detection and supervisory control capability. Ameren Missouri's plan is to convert these substations opportunistically over time as other capital projects are undertaken to replace their switching devices.

Capacitor Control and Volt-VAR Optimization

Smart line capacitor operation has helped Ameren Missouri maintain a consistent 98% distribution system power factor over the last twenty years. However, the capacitor control technology available today allows for feeder level efficiencies and degrees of optimization that were never before possible. The use of Volt-VAR Optimization as an

advanced distribution system application not only helps achieve these levels of efficiency and optimization, but also more effectively controls customer end-use voltages, and more reliably supports the reactive requirements of the transmission system. Ameren Missouri's intent is to leverage new ADMS system capabilities to integrate substation load monitoring with "smart" line capacitor operation for the first time in order to achieve these goals.

Ameren Missouri's first step as part of this automation strategy is the deployment of the next generation of "smart capacitor" technology on the distribution and subtransmission systems. Ameren Missouri will leverage the need to replace the existing 25-year old line capacitor control system in operation today in the St. Louis metro area for this deployment. To this end, all 2,300 of these capacitor controls will be upgraded over an accelerated period of five years due to the unavailability of legacy controls and the fact that no other hardware replacements are necessary as part of these upgrades.

Additionally, Ameren Missouri will be installing "smart" capacitors in place of the remaining 1,100 non-fixed units in the service territory. This deployment will take place over time by circuit, substation, or group of adjacent substations, coincident with the deployment of automated switches in order to maximize the associated communications investment.

After ADMS is implemented, Ameren Missouri will begin controlled experimentation with Conservation Voltage Reduction (CVR) as an energy and demand conservation measure. This will take place on a substation (or substation unit) basis as its distribution feeders are outfitted with "smart" capacitors and as degrees of voltage flattening and power factor optimization are confirmed. As Ameren Missouri validates the CVR application over time, consideration will be given to expanding it over wider areas of the service territory and over different times of day and seasons of the year. As this application is enabled with the ADMS platform and matures, more programmatic approaches can be adopted.

Dynamic Transmission Equipment Ratings

The daily transmission interchange activity generated from Ameren Missouri's geography and high degree of national grid connectivity results in its transmission facilities experiencing wide load swings all year round as opposed to just seasonally. The periodic recalculation of transmission equipment ratings based on the combination of equipment sensor outputs and meteorological data improves daily operations and solidifies contingency plans amidst heavy MISO and interchange sales activity.

In support of this, Ameren Missouri plans to outfit transmission substation transformers with comprehensive analysis monitors as a supplement to the winding temperature, bushing power factor, and dissolved gas sensors also being deployed, for purposes of

using their outputs to dynamically rate these units. This will be incorporated into the standard design of capital projects involving the construction or re-build of entire transmission substations as well as the installation or replacement of transmission substation autotransformers.

Ameren Missouri is also expanding the existing Phasor Measurement Unit (PMU) footprint on its transmission system to provide for more seamless operation across Regional Transmission Operator (RTO) boundaries. PMUs are high-resolution voltage, current, and frequency monitors outfitted at strategic locations on the transmission system. PMUs sample these electrical parameters many times a second, enhancing wide-area situational awareness for Transmission Operators and offering a more dynamic visibility into and synchronization with the rest of the nation's grid.

Ameren Missouri was able to negotiate with MISO for participation in its DOE-funded investment grant project, in which PMUs will be added at four Missouri system locations – Labadie Power Plant, Sioux Power Plant, and the Montgomery and Kelso transmission substations.

6.3.2.3 Customer Enablement & Use of Technology

AMR (Automated Meter Reading) vs. AMI (Advanced Meter Infrastructure)

Ameren Missouri will continue to evaluate the cost-effectiveness, timing, and applicability associated with a migration to Advanced Metering Infrastructure (AMI) technology from the Automated Meter Reading (AMR) technology currently deployed. Initial investigation indicates a full conversion to AMI would cost approximately \$300 million with an additional annual operating cost of \$10 million. Table 6.1 supports Ameren Missouri's position that most of the operational benefits of AMI are already being realized with the AMR system currently in operation. The few exceptions include two-way communication, remote connect and disconnect capability, remote meter programming, and advanced support for demand-side resources.

Ameren Missouri believes that today the benefits of an AMI conversion do not outweigh the costs. However, Ameren Missouri has been following AMI industry trends as well as exploring options for providing energy usage and pricing information to interested customers through means other than "smart" metering. Ameren Missouri is also tracking the degrees of success and ancillary issues associated with other utilities' deployments of "smart" meters around the country as a means of keeping current.

Table 6.1 Comparison of AMR vs. AMI Functionality

Feature/Functionality	AMR	AMI
Automated meter reading	✓	✓
Demand metering	✓	✓
Time-of-use metering	✓	✓
Interval data collection	✓	✓
Two-way communication	✗	✓
Demand response & critical peak pricing (15min)	✓ (Limited)	✓
Demand response & critical peak pricing (TOU blocks)	✓ (Limited)	✓
Home area networks/in-premise connectivity	✓ (Limited)	✓
In-home control of "Smart Appliances"	✓ (Limited)	✓
Outage management	✓ (Limited)	✓ (Limited)
Remote connect & disconnect	✗	✓
Revenue protection, theft detection	✓	✓
Asset monitoring/distribution automation	✓	✓
Prepaid metering	✓ (Limited)	✓
Online energy management	✓	✓
Automated load cycling or limiting	✓ (Limited)	✓
Improving customer service/satisfaction	✓	✓
T&D asset optimization	✓	✓
Future products/service offerings	✓ (Limited)	✓
Workforce optimization	✓	✓
Remote meter programming	✗	✓
Detection of meter problems and wiring errors	✓	✓
Improved locating of orphan meters	✓ (Limited)	✓ (Limited)

Note: "Limited" designates ability to provide the functionality with work-arounds and additional capital

Emerging Customer Technologies

Ameren Missouri continually follows the advancements and industry trends associated with emerging customer-owned products and technologies, especially as they influence the planning around their eventual penetration on Ameren's distribution system – these include electric vehicles, small-scale distributed generation and energy storage, smart appliances and Home Area Networks.

Ameren Missouri has taken a particular interest in the emergence of electric vehicles and is currently investigating opportunities for contributing to the region's overall preparedness. Ameren Missouri is studying the potential penetration of electric vehicles in the service territory and the resultant impact of vehicle charging on the distribution system. We are identifying the various business models possible in association with electric vehicles, including the utility interface, ownership of charging stations, and

possible rate structures associated with charging of these vehicles at home, at work, and in public places.

Ameren Missouri is also participating as a corporate member of the St. Louis Regional Clean Cities Plug-In Readiness Task Force as a means of following the initial discussions around being plug-in ready and identifying possible community partnering opportunities for technology promotion. Internally, Ameren Missouri is taking receipt of four PHEV bucket trucks in 2011 associated with an EPRI Demonstration project and is making arrangements with vehicle manufacturers for the early acquisition of EV/PHEV sedan models they plan to launch in Missouri. These activities are being pursued as a means of self-education and preparation for the energy advisor role Ameren Missouri is expecting to assume in this area with inquiring customers. Ameren Missouri is likewise taking active steps to render its own campus and operating centers plug-in ready, both for the sake of its growing electric fleet and its early-adopting employees.

AMI Impacts on DSM Programs

Integration into an AMI system allows DSM programs to communicate with the customer or their HAN (home area network) over one consolidated infrastructure, reducing the cost of program administration, marketing, and implementation. Without the AMI system, DSM programs will need to establish their own data infrastructure and their own method of communicating to customers; be it RF, pager, Internet, or other; thus reducing program cost-effectiveness. The particular DSM programs that would stand to benefit are Demand Response programs and Direct Feedback Energy Efficiency programs that involve an in-premise display device. It should be noted that these additional cost savings have been incorporated into the AMI evaluation. In addition, the demand-side analysis detailed in Chapter 7 includes an assumption of full AMI deployment starting in 2015.

6.4 Compliance References

4 CSR 240-22.040(3)	7
4 CSR 240-22.040(6)	7
4 CSR 240-22.040(7)	1
EO-2007-0409 – Stipulation and Agreement #14	7
EO-2007-0409 – Stipulation and Agreement #16	1
EO-2007-0409 – Stipulation and Agreement #17	1

7. Demand-Side Resources

Highlights

- Ameren Missouri has conducted a DSM Market Potential Study with primary data from its service territory to assess the potential for energy and demand savings
- A total of 425 demand side measures have been evaluated
- Ameren Missouri plans to spend nearly \$60 million over 3 years on energy efficiency programs to obtain nearly 253 GWh of energy savings and over 54 MW of peak demand savings.
- Business Custom Program incentive levels increased by over 50% from prior implementation plan levels.
- The budget for the Residential HVAC program has increased more than 25% from the Cycle 1 budget to position it as one of the premier program offerings.
- The innovative Multi-family Income Qualified program will continue and may be expanded depending on how Ameren Missouri and stakeholders determine how best to serve hard-to-reach customer segments.

Ameren Missouri has undertaken significant steps to improve and expand its consideration and evaluation of demand side resources. Chief among these is the development of a DSM Market Potential Study, which relies on primary market research within Ameren Missouri's franchise service territory. Using the results of this study, Ameren Missouri has developed a range of potential DSM portfolios for evaluation in the integration and risk portions of the IRP analysis.

7.1 Implementation Plan Summary

7.1.1 Introduction

The implementation plan covers a three year period beginning on January 1, 2012 and extending through December 31, 2014. The following table summarizes the estimated energy and demand savings and costs estimated for this period.

Table 7. 1: Estimated Incremental Savings and Costs for the Implementation Period - LOW RISK Portfolio

	<u>2012</u>	<u>2013</u>	<u>2014</u>
Estimated energy savings (MWh)	100,378	80,393	73,064
Estimated demand reduction (MW)	18	17	19
Estimated costs (Program costs in millions)*	\$ 20.50	\$ 18.76	\$ 20.17

* Note: The Company may choose to equalize expenditures for each year after finalizing implementation plans with its implementation contractors.

As stated above, this document focuses primarily on the years 2012 through 2014, which is the second 3-year implementation cycle ("Cycle 2") of Ameren Missouri's ongoing DSM programming. Analysis was also performed for all other years in the Integrated Resource Planning (IRP) horizon (2010-2030). Several demand side management (DSM) portfolios were analyzed and considered during this process. The list of all DSM portfolios considered has been enumerated below in ascending order of impact and budget. More detail has been provided on the development of the various portfolios in Section 7.8.

- **Low Risk Portfolio (Low Risk):** reduces Cycle 1 levels of program spending and savings to a level commensurate with the Company's growing concerns with the current DSM regulatory framework, especially lost revenues. This portfolio only slightly escalates these levels over time.
- **Capacity Calibrated Portfolio (CCP):** tuned to meet only annual capacity needs during the planning horizon.
- **Realistic Achievable Potential Portfolio (RAP):** version of the RAP identified in Ameren Missouri's foundational DSM Market Potential Study found in Appendix B, updated with the latest information and assumptions from the IRP process.
- **Maximum Achievable Potential Portfolio (MAP):** version of the MAP identified in Ameren Missouri's foundational DSM Market Potential Study, updated with the latest information and assumptions from the IRP process.
- **1% Per Year Portfolio (1PPY):** very aggressive portfolio designed to achieve 1% incremental energy savings every year after 2015. Designed to be equivalent to MAP.
- **2% Per Year Portfolio (2PPY):** extremely aggressive portfolio designed to achieve 2% incremental energy savings every year after 2020.¹

7.1.2 Portfolio Programs

The Low Risk portfolio represents a robust set of energy efficiency measures that have been aggregated into programs. The programs were designed to incorporate considerations of new building construction, thermal integrity, equipment and appliance

¹ ER-2010-0036 – Stipulation and Agreement #12a;
EO-2007-0409 – Commission Order for 4 CSR 240-22.050(4)

efficiency, and utilization levels of energy-using capital stock.² The table below represents a high level summary of the proposed programs.

Table 7. 2: Low Risk Portfolio Programs³

Residential - Lighting	Incentives are provided to the manufacturing and retail partners to increase sales of qualified lighting whereby the end-user receives a discount on the price of ENERGY STAR qualified or other high efficiency lighting products.
Residential - HVAC	HVAC diagnostics/tune-up, retrofit, and replacement upgrades for air conditioners, heat pumps, and cooling systems, achieving electric energy savings.
Residential - Appliance Recycling	An incentive is provided to a customer for removing an inefficient refrigerator or freezer whereby a turnkey appliance recycling company verifies customer eligibility, schedules pick-up appointments, picks up appliances, recycles and disposes units, and performs incentive processing.
Residential – Low Income	Delivers energy savings to low income qualified customers through direct install measures and incentives for energy efficient appliances.
Business – Standard Incentive	Incentivizes customers to purchase energy efficient measures with predetermined savings values and fixed incentive levels.
Business – Custom Incentive	Applies to energy efficient measures that do not fall into the Standard Incentive program. These projects are often complex and unique, requiring separate incentive applications and calculations of estimated energy savings.
Business - Retro-Commissioning	This program has a special focus on complex control systems and provides options and incentives for businesses to improve operations and maintenance practices for buildings, systems, and processes, achieving electric energy savings.
Business - New Construction	Provides incentives to overcome cost barriers to incorporating energy efficient building design and construction to achieve electric energy savings.
Business Multi-family	Focusing on common area lighting improvements and whole building HVAC system upgrades/replacement, multi-family buildings will be able to leverage incentives to improve energy performance. This program may be integrated into the Business Standard Incentive program.
Residential Demand Response – Direct Load Control	The purpose of the program is to reduce customer load and increase system reliability through command and control applications.
C&I Demand Response – Direct Load Control	The program seeks to reduce customer demand through installation of command and control switches on commercial customers systems.

² 4 CSR 240-22.050(1)(B)

³ 4 CSR 240-22.050(11)(G)

7.1.3 Portfolio Overview

The Low Risk portfolio is the set of Energy Efficiency Programs included in its preferred plan. This is a portfolio that:

- **Is cost-effective** at the measure, program, and portfolio level. The overall portfolio benefit-cost ratio using the Total Resource Cost test is **1.81** (included Demand Response).
- **Aligns with best practice.** The program designs selected for this portfolio have been based on a review of program experience across the country as reflected in various studies of best practice by the American Council for an Energy Efficient Economy, the Consortium for Energy Efficiency, the National Action Plan for Energy Efficiency, and the U.S. Environmental Protection Agency.
- **Is flexible and mitigates risk.** By selecting this portfolio, Ameren Missouri is committing to its overarching elements: namely the energy savings goals and the budgets to achieve them. Specific program designs are still conceptual. Incentive levels are still broadly and formulaically developed. The details of program implementation have only been broadly sketched in the program templates found in Chapter 7 - Appendix A. Detailed program design and implementation planning typically occur after the Commission reviews the Company's IRP planning process. Once the review process is complete, the Company works with implementation contractors (or subcontractors) to develop more detailed plans that include specific incentive levels, participation levels, and implementation plans. This will allow the Company to bring a third party implementation contractor's expertise (or in-house management expertise) into the process before the program design is complete. The Low Risk portfolio plan is based on a formal assessment of the risks associated with each program and is designed to manage those risks, but exact adherence to this plan is neither intended nor probable. A key element of the risk management strategy is the flexibility to shift resources within the portfolio – to modify portfolio composition and risk as the market responds to our programs.
- **Is scalable** and enables the Company to ramp programs up or down as needed. It is not possible, at this stage in the process, to predict precisely how the market will accept each program. Therefore, having programs within the portfolio that can be quickly scaled up or down is essential to enable a rapid response to changing plan targets and market realities.
- **Represents a diverse cross-section of opportunities** for customers of all rate classes to participate in the programs.
- To the extent possible, **coordinates with other existing efforts.** The programs are working to coordinate with the natural gas energy efficiency programs offered by Ameren Missouri. The Company is also working with Laclede Gas to improve

coordination between natural gas/electric energy efficiency programs that address opportunities to improve the heat gain/loss characteristics of buildings.

7.1.4 Key Changes for Cycle 2

The Cycle 2 portfolio includes many enhancements, improvements, and evolutions relative to the Cycle 1 portfolio. The key changes for Cycle 2 are:

- Incorporated information gleaned from implementation experience in Cycle 1.⁴
- Primary market research from the DSM Potential study was used to inform program design and identify achievable energy savings potential. This granularity was absent in the previous 2008 IRP filing.⁵
- New modeling software, DSMore, was used to calculate cost-effectiveness for each measure, program, and portfolio.
- Decreasing program efforts surrounding CFL sales to reflect the expected impacts of Energy Independence and Security Act 2007 ("EISA").
- Re-evaluation of motors/drives within the Business Programs. In order to garner savings from this hard-to-reach market segment, increased marketing and incentive dollars have been allocated to help transform the commercial and industrial motors/drives market.
- Decreased reliance on the prime contractor implementation model for the Residential portfolio. This contractor model, however, appears to be working well in the business portfolio, so it has remained as the primary implementation model.
- Increased administrative costs to comply with the expected filing requirements of Missouri Senate Bill 376 otherwise known as the Missouri Energy Efficiency Investment Act ("MEEIA"). As discussed later in this document, significant allocation of company resources will be required.

The following table summarizes annual incremental portfolio energy savings, demand savings, and program costs for the 3-year implementation planning period.

⁴ EO-2007-0409 – Stipulation and Agreement #27; EO-2007-0409 – Stipulation and Agreement #29

⁵ EO-2007-0409 – Stipulation and Agreement #27; 4 CSR 240-22.050(07)(A)1;
EO-2007-0409 – Commission Order for 4 CSR 240-22.050(07)(A)1

Table 7. 3: Ameren Missouri Portfolio Summary for Cycle 2 (2012-2014)

LOW RISK	Incremental GWh			Incremental MW			Budget (millions of \$)		
	2012	2013	2014	2012	2013	2014	2012	2013	2014
Lighting	44.3	30.5	17.1	1.3	0.9	0.5	\$3.78	\$2.70	\$1.53
HVAC	9.2	10.8	14	4.4	5.1	6.5	\$3.11	\$3.74	\$4.95
Appliance Recycling	7.0	3.9	3.4	1.0	0.6	0.5	\$1.65	\$0.95	\$0.89
Low Income	3.3	2.8	2.2	0.2	0.2	0.2	\$2.78	\$2.96	\$3.12
EE Residential Total	63.9	48.1	36.8	6.9	6.8	7.7	\$11.32	\$10.34	\$10.49
Standard	9.8	11.5	13.7	3.9	4.6	5.5	\$2.90	\$3.35	\$3.94
Custom	23.6	17.7	19.2	6.3	4.8	5.3	\$5.57	\$4.26	\$4.75
RCx	1.0	0.8	0.8	0.2	0.2	0.2	\$0.11	\$0.09	\$0.08
New Construction	1.2	1.4	1.7	0.4	0.5	0.6	\$0.43	\$0.54	\$0.71
Multifamily Common	0.9	0.9	0.9	0.2	0.2	0.2	\$0.17	\$0.19	\$0.21
EE Business Total	36.5	32.3	36.3	10.9	10.2	11.7	\$9.18	\$8.42	\$9.69
EE PORTFOLIO TOTAL	100.4	80.4	73.1	17.8	17.0	19.4	\$20.50	\$18.76	\$20.17
	Total System Energy (GWh)			Total System Peak (MW)			Total Revenue Requirements (million \$)		
	2012	2013	2014	2012	2013	2014	2012	2013	2014
Ameren Missouri									
Baseline Forecasts	41,035	41,291	41,601	8,318	8,380	8,425	\$3,034	\$3,251	\$3,474
DSM as %	0.24%	0.19%	0.18%	0.22%	0.20%	0.23%	0.68%	0.58%	0.58%

The graphs on the following pages summarize portfolio cumulative energy savings, cumulative peak demand savings, and annual program costs for the planning horizon.

It should be noted that 2010 and 2011 reflect plans from the previous 3-year implementation plan (Cycle 1) that are already in motion. Also, no demand response ("DR") programs are part of the upcoming implementation plan (Cycle 2), but are planned to begin in 2016. A more detailed description of the energy savings and demand reduction calculations for each program can be found in the Electronic Work Papers "BatchTool_(desired program name).xlsx".

Figure 7. 1: Ameren Missouri EE Annual Budget

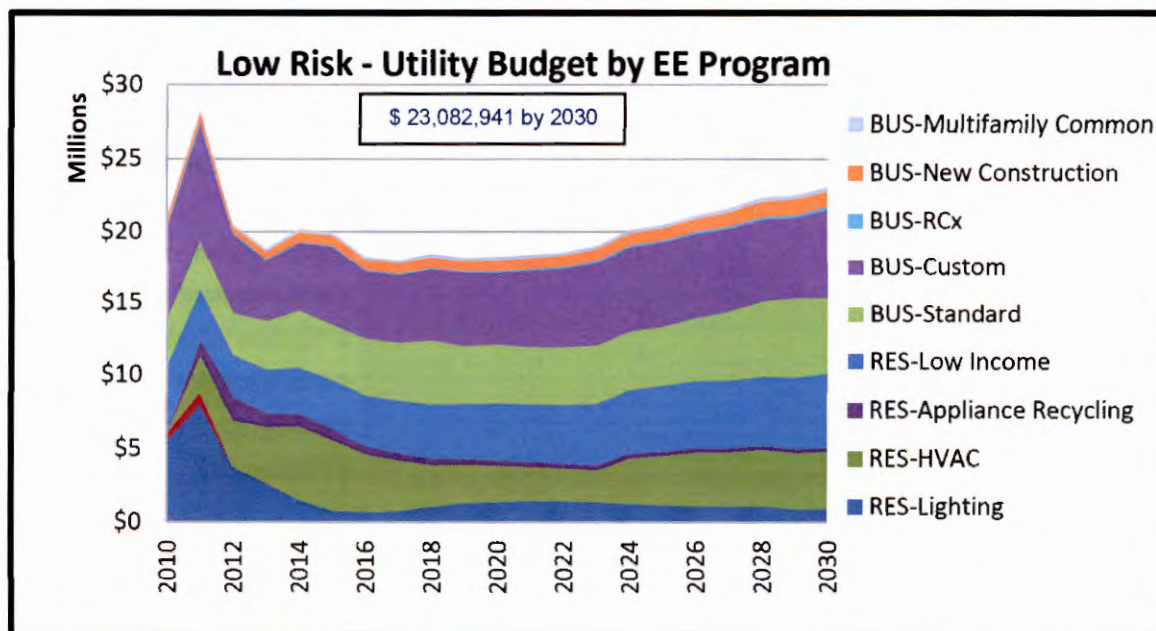


Figure 7. 2: Ameren Missouri EE Cumulative Energy Impacts

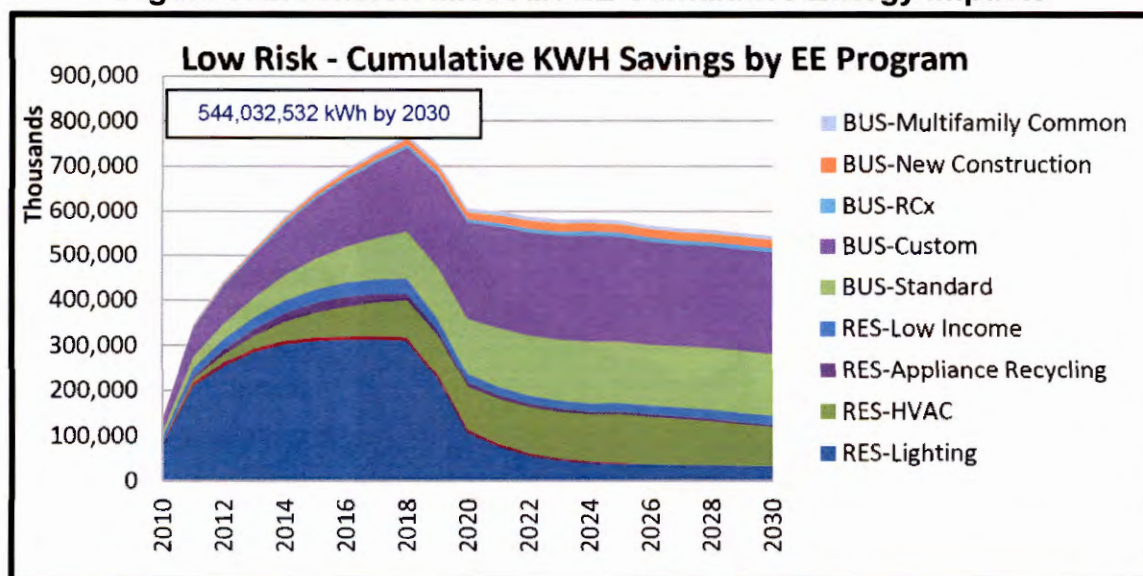


Figure 7. 3: Ameren Missouri EE Cumulative Peak Demand Impacts

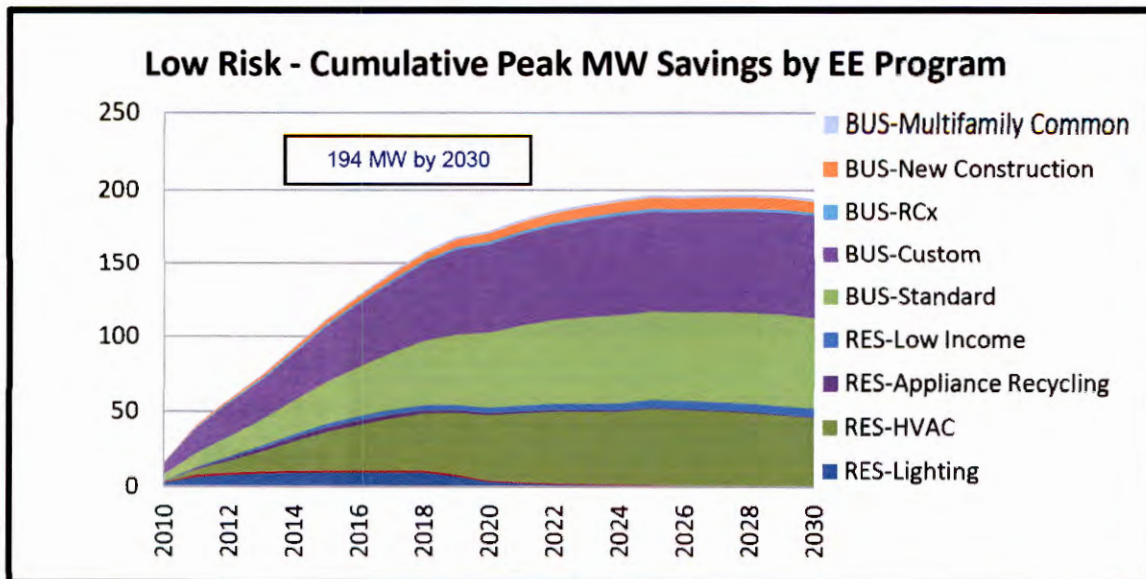


Figure 7. 4: Ameren Missouri DR Annual Budget

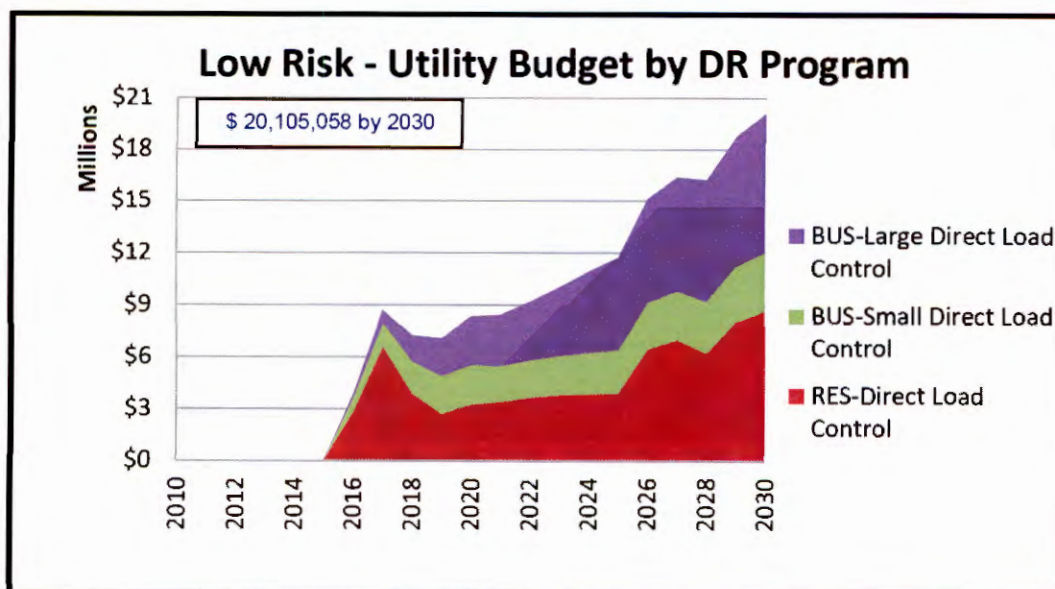


Figure 7. 5: Ameren Missouri DR Cumulative Peak Demand Impacts

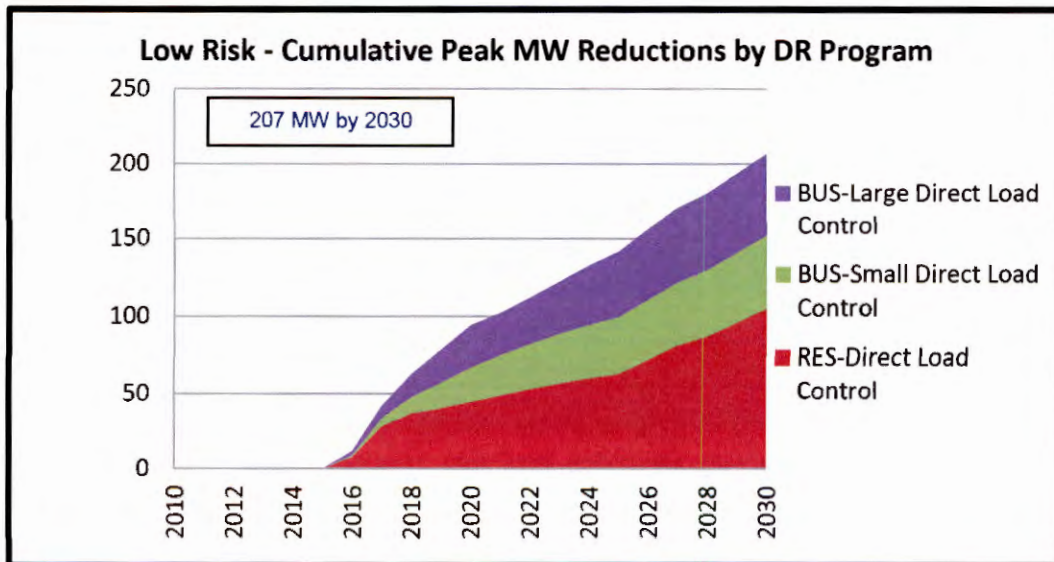


Figure 7. 6: Ameren Missouri Combined EE & DR Annual Budget

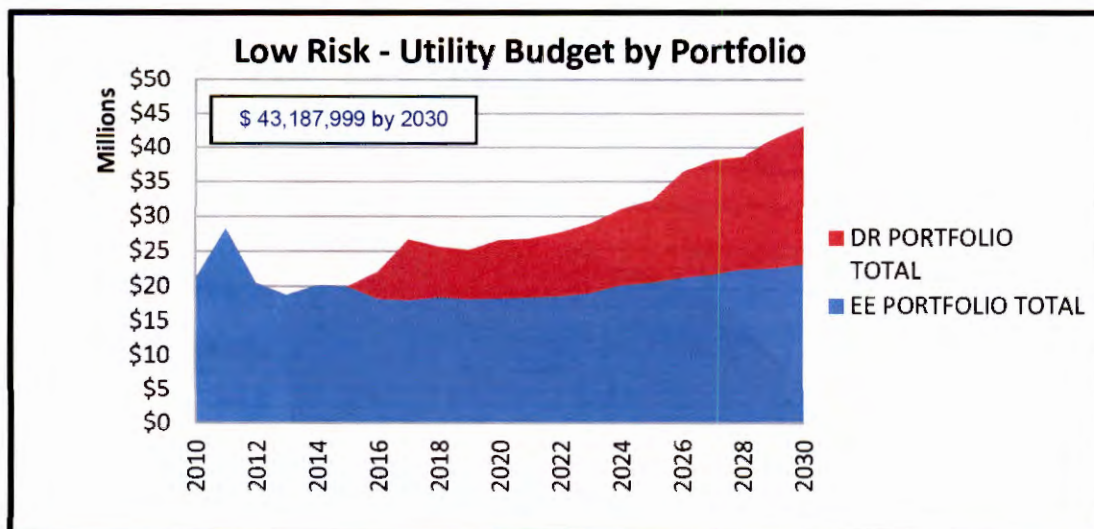


Figure 7. 7: Ameren Missouri Combined EE & DR Cumulative Energy Impacts

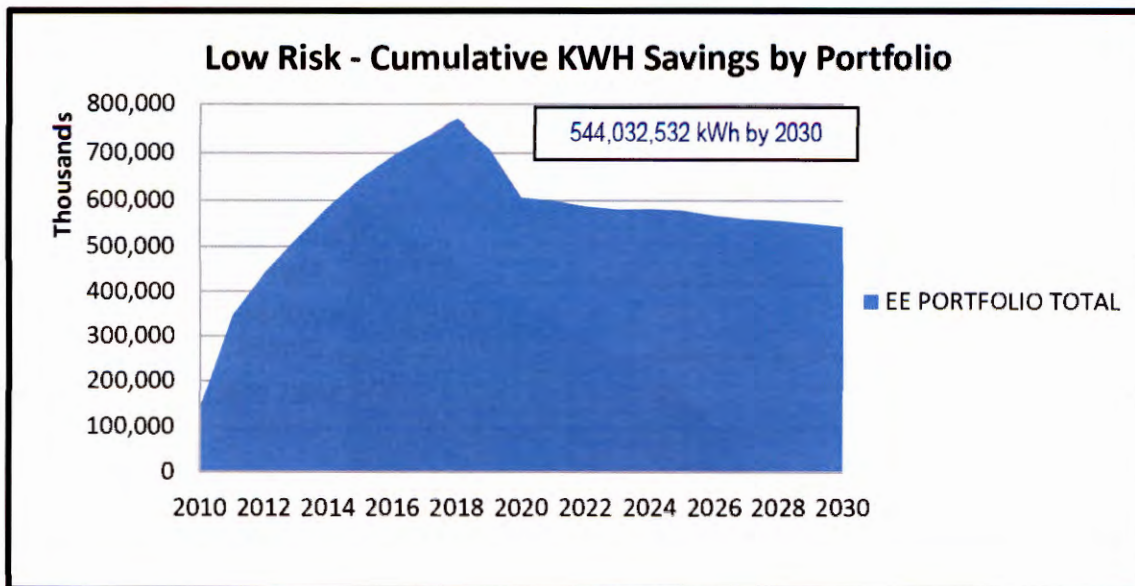


Figure 7. 8: Ameren Missouri Combined EE & DR Cumulative Peak Demand Impacts

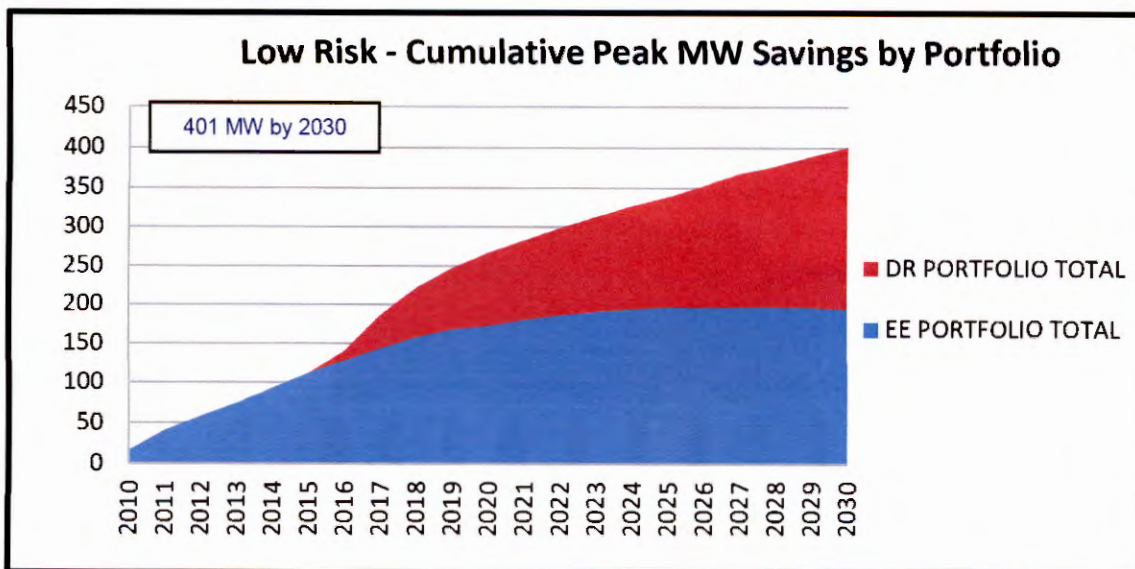


Table 7. 4 shows the cost-effectiveness tests for the portfolio of programs for the planning horizon. Please see Section 7.2.3 for definitions and further detail.

Table 7. 4: Cost Effectiveness Tests⁶

LOW RISK Portfolio				
	TRC	UCT	PCT	RIM
ENERGY EFFICIENCY				
RES-Lighting	1.99	4.66	3.29	0.70
RES-HVAC	1.42	3.19	1.85	0.83
RES-Appliance Recycling	1.31	1.31	-	0.51
RES-Low Income	0.65	0.65	2.25	0.39
RES-TOTAL	1.43	2.47	2.53	0.68
BUS-Standard	2.10	3.34	2.93	0.94
BUS-Custom	2.06	3.55	3.19	0.83
BUS-RCx	2.55	5.23	4.85	0.64
BUS-New Construction	1.70	2.39	2.95	0.83
BUS-Multifamily Common	1.66	3.39	2.48	0.77
BUS-TOTAL	2.05	3.41	3.10	0.86
PORTFOLIO TOTAL	1.75	2.96	2.80	0.78
DEMAND RESPONSE				
RES-Direct Load Control	2.59	N/A because	N/A because	N/A because
RES-TOTAL	2.59	same as TRC	can't determine	costs are less
BUS-Small Direct Load Control	2.69		cost of businesses	than savings
BUS-Large Direct Load Control	1.48		to shut down	so the only
BUS-TOTAL	1.94		operations	impact is lost
PORTFOLIO TOTAL	2.23			revenues
EE AND DR PORTFOLIO TOTAL	1.81			

The levelized cost in average nominal dollars for the LOW RISK portfolio over the planning horizon is shown below in Table 7. 5 Please see Electronic Work Papers ("Portfolio LOWRISK_Levelized_costs_rollup_2010-12-02.xlsx") for a more detailed description of how the levelized costs were calculated.⁷

⁶ 4 CSR 240-22.050(7)(D), 4 CSR 240-22.050(11)(I)

⁷ EO-2007-0409 – Stipulation and Agreement #21

Table 7. 5: Levelized Costs

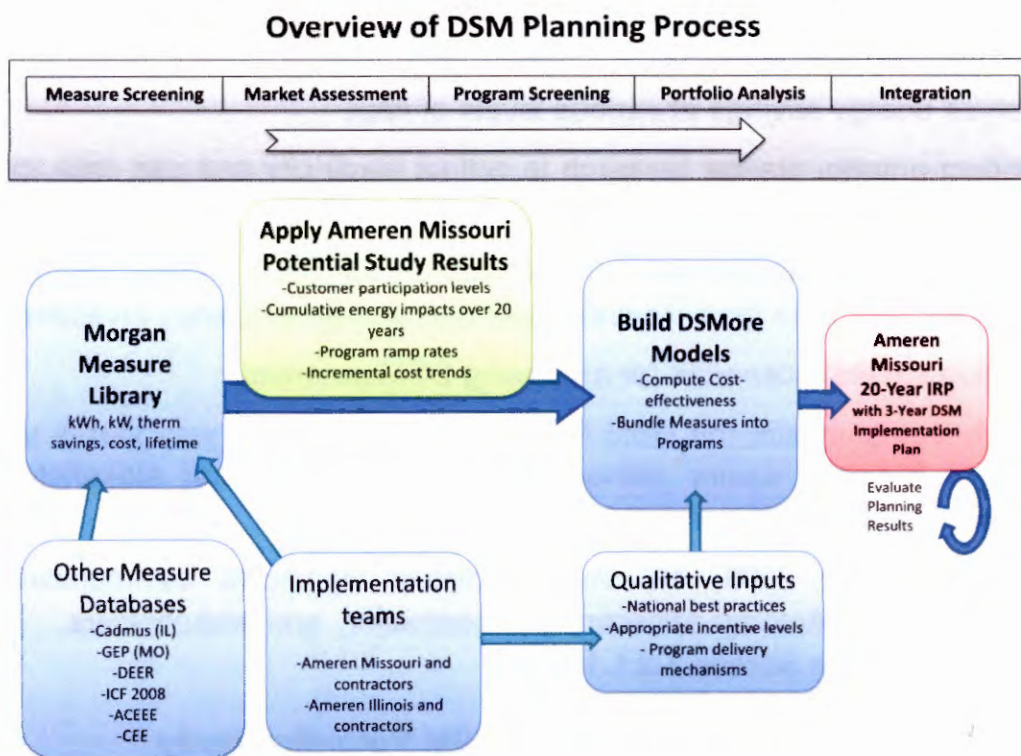
LOW RISK			
All Years: 2010-2030	Nominal Levelized UTILITY Cost / kWh		Nominal Levelized TRC Cost / kWh
RES-Lighting	\$	0.014	\$ 0.044
RES-HVAC	\$	0.053	\$ 0.144
RES-Appliance Recycling	\$	0.056	\$ 0.056
RES-Low Income	\$	0.170	\$ 0.170
RES-TOTAL	\$	0.040	\$ 0.080
BUS-Standard	\$	0.041	\$ 0.076
BUS-Custom	\$	0.036	\$ 0.071
BUS-RCx	\$	0.022	\$ 0.056
BUS-New Construction	\$	0.058	\$ 0.092
BUS-Multifamily Common	\$	0.034	\$ 0.084
BUS-TOTAL	\$	0.038	\$ 0.073
EE PORTFOLIO TOTAL	\$	0.039	\$ 0.076

7.2 The Planning Process

Ameren Missouri's portfolio for Cycle 2 contains a substantial list of improvements to the planning process from methods previously employed for Cycle 1. A primary improvement is the knowledge gained from the actual program implementation and evaluation experience of Cycle 1. Another primary improvement is the incorporation of a substantial DSM market potential study with primary market research data for Ameren Missouri customers.⁸ Development of the plan also reflects: (1) the acquisition of the DSMore™ model – the leading cost effectiveness tool for energy efficiency and demand response programs; (2) the acquisition of multiple measure level databases; (3) a robust economic screening process including approximately 500 electric energy efficiency measures; and (4) a review of utility program design best practices. The flow of the overall planning process has been illustrated in Figure 7. 9 and is described in more detail in Section 7.2.5.

⁸ 4 CSR 240-22.050(5)

Figure 7. 9: Overview of DSM Planning Process*



* Acronyms used in this diagram are as follows: Global Energy Partners (GEP), Database for Energy Efficient Resources (DEER), American Council for an Energy-Efficient Economy (ACEEE), Consortium for Energy Efficiency (CEE), Demand Side management (DSM).

7.2.1 DSM Market Potential Study

As a foundational step in the DSM planning process, Ameren Missouri selected Global Energy Partners (GEP) through a competitive bidding process to conduct a rigorous DSM market potential study. The study employed extensive primary market research on Ameren Missouri customers in order to estimate potential energy efficiency and demand response savings and costs.⁹ A summary of the DSM market potential study is included in Appendix B and the entire study is attached in the Electronic Work Papers ("Studies" folder).¹⁰

One of the primary reasons to conduct the potential study was to have a factual basis on which to gauge the reasonableness or aggressiveness of DSM efforts. Key objectives for this study were to:

⁹ 4 CSR 240-22.050(5)

¹⁰ 4 CSR 240-22.050(11)(E)

1. Assess and understand technical, economic, achievable and naturally occurring potential for all customer segments in the Ameren Missouri service area from 2009 to 2030.
2. Analyze energy savings at various levels of cost.
3. Conduct primary market research to collect electricity end-use data, customer demographics and psychographics.¹¹
4. Understand how customers in the Ameren Missouri service territory make decisions related to their electricity use and energy efficiency investments.¹²
5. Develop several scenarios for assessing DSM potential.
6. Clearly communicate the DSM Potential in an objective way that is useful for Ameren Missouri senior management, Ameren Missouri stakeholders and Ameren Missouri DSM and IRP staff.

Conducted throughout 2009, the study included significant communication and coordination between Ameren Missouri, the contractor, and stakeholders. This has been outlined in detail in Section 7.2.1.1.

7.2.1.1 Stakeholder Interactions During DSM Potential Study

A number of Stakeholder workshops were held regarding the development of the Ameren Missouri Demand Side Market Potential Study, which was used as a key input in the development of the Ameren Missouri DSM Portfolios that are analyzed within the IRP.¹³

February 4, 2009: An Introductory Stakeholder Workshop was held that identified the study team members, the study objectives, and tasks to be performed in the study. Stakeholder comments and suggestions were requested and a list of action items was developed and addressed in the following weeks.

April 7, 2009: As part of the action items follow-up to the February 4, 2009 meeting, the Measure list inputs were developed and distributed for Stakeholder comment. Stakeholder comments were prepared and received by Ameren Missouri.

May 20, 2009: Stakeholder comments on the Measure list inputs were prepared and received by Ameren Missouri, and were incorporated into the final version of the Measure list, as "EE Measures and DR Options_Ameren Missouri_2009-05-20.xls".

June 23, 2009: A Stakeholder Workshop was held to provide a DSM Market Potential Study Status Update. During the meeting the measure list that would be screened was identified, along with the adjustments to the list as provided by the Stakeholders.

¹¹ EO-2007-0409 – Stipulation and Agreement #23

¹² 4 CSR 240-22.050(1)(B)

¹³ EO-2007-0409 – Stipulation and Agreement #24

October 29, 2009: The next Stakeholder workshop included an update for the Ameren Missouri DSM Market Potential Study related to the Market Research results and the status of the remaining work for the study. The workshop also covered a number of subjects related to current EE program activities as well as the results of a recently completed Ameren Missouri Distributed Generation Market Penetration Assessment. Stakeholder comments and suggestions were accepted during the workshop.

January 28, 2010: The Final Report for the Ameren Missouri DSM Market Potential Study (a four volume report showing all steps of the study as well as the results and interpretation of the study results) was distributed to the Stakeholder group.

February 4, 2010: The Final Report for the Ameren Missouri Market Potential Study was discussed during a Stakeholder Workshop. The workshop provided an overview of the Study, along with the results of the study. As with the previous workshops, Stakeholder comments and suggestions were accepted during the workshop.

Following this meeting there have been a number of “Post-Study” interactions between the Stakeholders and Ameren Missouri:

February 11, 2010: The Missouri Department of Natural Resources (MDNR) submitted a number of questions related to the content of the study, via email. The subject of these questions was:

- Terminology
- Survey samples
- Data and inputs
- Energy potential benefits and supply curves
- Energy savings baselines
- Economic potential in the commercial sector

March 3, 2010: Ameren Missouri provided responses to the questions that were presented by the MDNR on February 11, 2010.

March 11, 2010: Ameren Missouri hosted a WebEx based discussion between the study contractors and the Stakeholders covering the responses provided on March 3, 2010.

March 18, 2010: Ameren Missouri hosted a follow-up teleconference to the March 11, 2010 WebEx, with David Lineweber, who led the market research work for the contractor team that prepared the study, and Mr. Adam Bickford, of the Missouri Department of Natural Resources (MDNR), to specifically address sample design.

April 1, 2010: Ameren Missouri issued a follow-up memo to Stakeholders via email that was thought to address all known comments and concerns that had been expressed by the Stakeholder group to date regarding the Ameren Missouri DSM Market Potential Study.

July 14, 2010: Mr. Adam Bickford (MDNR) sent memos to Ameren Missouri via email identifying additional concerns with the Ameren Missouri Market Potential Study memo and the market research methodologies used in the study.

July 15, 2010: Mr. Adam Bickford (MDNR) presented his concerns from the memos at the Ameren Missouri Regulatory Stakeholder Quarterly DSM meeting

August 11, 2010: Ameren Missouri distributed memos addressing Mr. Adam Bickford's concerns that were presented on July 15, 2010.

Ameren Missouri believes that its potential study represents the state-of-the-art of DSM Potential studies. The study depicts achievable potential in the Company's service territory based on primary market research data.

7.2.1.2 Definition of Potentials

Below are key definitions of DSM potentials that were assessed in the Study:

- **Technical potential** is a theoretical construct that assumes customers will adopt all feasible measures, regardless of cost or customer preferences.¹⁴
- **Economic potential** is a theoretical construct that assumes customers will adopt all cost-effective measures, regardless of customer preferences and market barriers.
- **Maximum achievable potential (MAP)** takes into account expected program participation, based on customer preferences resulting from ideal implementation conditions. MAP establishes a maximum target for the EE and DR savings that a utility can hope to achieve through its EE and DR programs and involves incentives that represent a substantial portion of the incremental cost combined with high administrative and marketing costs. It is commonly-accepted in the industry that MAP is considered the hypothetical upper-boundary of achievable savings potential simply because it presumes conditions that are ideal and not typically observed in real-world experience.
- **Realistic achievable potential (RAP)** represents what the industry considers to be realistic estimates of EE and DR potential based on realistic parameters associated with DR and EE program implementation (i.e., industry-standard incentive levels, customer acceptance barriers, etc.). RAP corresponds to best practices that are typically attainable since the estimates are tied to known program experience from around the country.

¹⁴ 4 CSR 240-22.050(04)

7.2.1.3 Key Findings

The study enlightened Ameren Missouri about its customer base and the potential for energy savings and peak demand reductions that are possible through energy-efficiency (“EE”) and demand response (“DR”) programs. The key highlights are as follows:

- There is more opportunity for program savings than was estimated using secondary data. Achievable potential is higher than what was included in the Ameren Missouri 2008 IRP.
- Concurrent with higher opportunities, budgets to harvest those opportunities reach an annual spend range of \$100 million to \$200 million by 2015. This range corresponds to roughly 2% and 5% of projected Ameren Missouri revenues, a spending level which exceeds nearly all electric utilities in the nation.
- A comprehensive view of measures yielded considerable economic potential. The study considered hundreds of measures and there are very significant savings opportunities.
- Ameren Missouri customers are different than others in the nation. They typically express less interest in DSM investments at this time.

Using a bottom-up, end-use approach, Global Energy Partners assembled models of equipment stock and energy usage throughout the time horizon that were based on the primary market research data of the Ameren Missouri service territory.¹⁵ They then applied EE and DR measures and programs to the model at levels defined by the extensive attitudinal research in order to estimate the potential energy saving effects. Each set of results has been briefly summarized below, and full detail is available in the 4 volume report which is publicly available on Ameren’s website.

Energy Efficiency Potential

- Realistic achievable potential in 2030 represents a reduction of 7.3% of the total forecasted baseline usage for that year. This represents 25% of technical potential and 44% of economic potential.
- Maximum achievable potential in 2030 represents a reduction of 11.0% of the total forecasted sales in 2030. This represents more than a third of technical potential and nearly two-thirds of economic potential.

In addition to energy savings, energy efficiency programs also create savings in coincident peak demand. The savings are substantial because many of the EE savings result from measures related to air conditioning across all sectors, C&I

¹⁵ 4 CSR 240-22.050(05)

lighting, and motors, all of which have high usage during peak periods. These EE peak demand savings have been combined with DR peak demand savings in the following discussion.

Demand Response Potential

- Realistic DR achievable potential in 2030 represents a reduction of 10.0% of the total forecasted peak demand for 2030.
- Maximum DR achievable potential in 2030 represents a reduction of 12.3% of the total forecasted peak demand for 2030.

Combined Peak Demand Savings

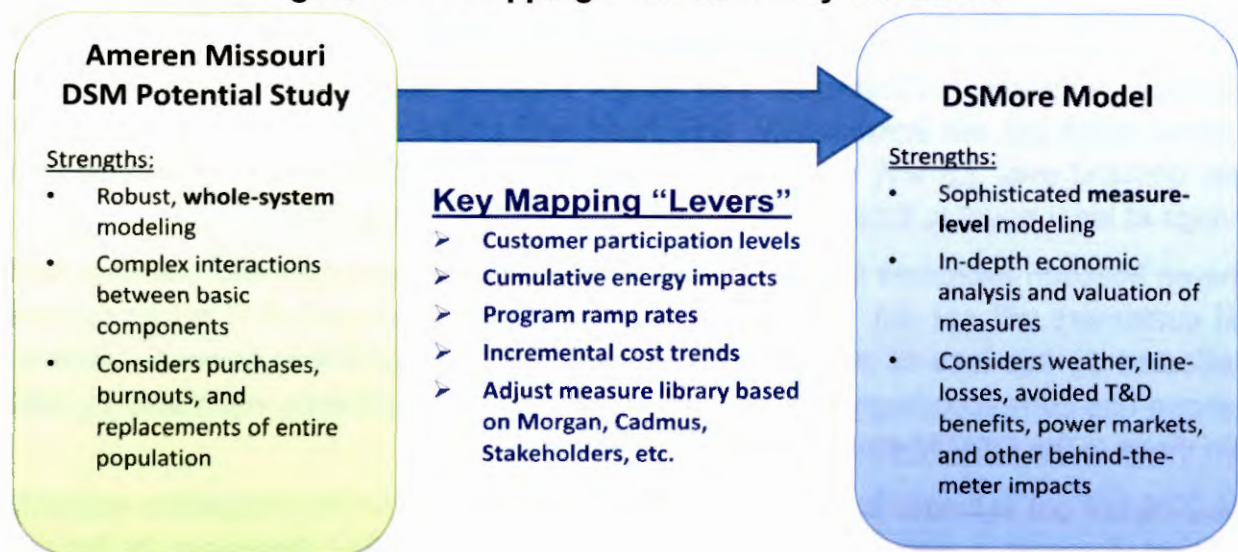
Throughout the forecast period, peak demand savings from EE programs for RAP and MAP are about the same as the savings from DR programs. However, in contrast to DR programs, the peak-demand savings from EE programs are permanent and non-dispatchable. Together, these peak demand savings are quite substantial:

- Realistic achievable potential of EE and DR in 2030 represents a reduction of 19.2% of the total forecasted peak demand for 2030.
- Maximum achievable potential of EE and DR in 2030 represents a reduction of 26.1% of the total forecasted peak demand for 2030.

7.2.1.4 Mapping of Potential Study to Planning Assumptions

Several outputs of the Ameren Missouri DSM Market Potential Study required translation or mapping in order to become appropriate inputs for the Ameren Missouri IRP team. Ameren Missouri acquired “DSMore” modeling software (discussed in detail in Section 7.2.5.1) in order to have a more sophisticated cost-effectiveness analysis at the measure level. It was necessary to map the various components of the GEP study to this updated analysis framework. This has been illustrated in the figure below.

Figure 7. 10: Mapping Potential Study to DSMore



The GEP measure database and Ameren Missouri’s updated measure database each included hundreds of measures. To reconcile these databases, several adjustments were made to measure data including specifying values on a “per installation” basis instead of a “per square foot” basis, and matching measures that had disparate naming conventions or baseline assumptions. We also verified that savings, costs (exclusive of utility marketing, program delivery, and lost revenues), and lifetimes matched up after the reconciliation.¹⁶

GEP then provided Ameren Missouri with the participation levels, program ramp rates, and incremental cost trends over the planning horizon such that the overall energy impacts were approximately equal to the Realistic Achievable Potential (RAP) and Maximum Achievable Potential (MAP) from the Ameren Missouri’s DSM Market Potential Study.¹⁷ With these values, Ameren Missouri was then ready to begin the actual portfolio analysis required for the IRP.

7.2.2 Effects of Missouri Energy Efficiency Investment Act

In 2010, the Missouri Public Service Commission submitted new rules to the Secretary of State to implement the Missouri Energy Efficiency Investment Act (MEEIA). Provisions of MEEIA affected the DSM planning process in multiple ways. First, the rules allowed certain commercial and industrial customers to opt out of energy efficiency programs and any associated surcharges on their bills. The rules also call for a number of administrative, filing, and tracking exercises that will substantively increase the costs associated with DSM.

¹⁶ 4 CSR 240-22.050(03)(D)

¹⁷ 4 CSR 240-22.050(07)(A)

Business Customer Opt Out

MEEIA would allow eligible large business customers to opt out of utility energy efficiency programs. Customers with single facilities exceeding 5.0 MW of peak demand could opt out immediately, and those with accounts that can aggregate to a peak demand over 2.5 MW can do so given that they demonstrate an achievement of savings at least equal to those expected by utility-provided programs.

Ameren Missouri estimates in its planning that 20% of the available DSM potential from C&I customers will opt out. The Low Risk portfolio is sized such that it can operate unaffected by this loss of potential. In more aggressive portfolios, however, Ameren Missouri has correspondingly reduced its business program potential estimates by 20% from those in the DSM Market Potential Study.

The 20% opt out estimate is the base case assumption used in the integration analysis. However, there were also a high case (35%) and a low case (5%) developed for the risk analysis. Because this law is new and there is no experience to base expectations on, there is a great deal of uncertainty around which customers will act on the opt out provision. The estimates were developed by trying to ascertain the highest and lowest levels that would be possible given the law's provisions. The base case was assumed to be the midpoint between those more extreme scenarios.

The low case was based off of an analysis of the load that has already notified Ameren Missouri of its intention to opt out of energy efficiency programs. Nine customers have already provided such notification. One of those, customers, Noranda Aluminum, is large enough to be handled separately in such analysis. The aggregated annual load for the remaining eight customers was compared to an estimate of the annual total Commercial and Industrial ("C&I") class loads to determine that 5% of the C&I class had already opted out. This makes a logical lower bound for the total load that will ultimately opt out.

The upper bound for opt out potential was developed by doing detailed analysis from the Ameren Missouri billing system to identify potential customers that would qualify for the opt out provision. First, customers that met the 5 MW threshold per their 2009 billing demand were identified to immediately qualify for opt-out. That list was adjusted for the fact that two customers on it had already closed or announced their intention to close their operations. Once again, the Noranda load was also removed from the list, as it is large enough to be treated separately. The annual MWh consumption for the remaining 5 MW customers for the year 2009 was aggregated as one group of opt out eligible load.

Next, individual accounts greater than 2.5 MW were identified and a similar aggregation of the associated annual consumption was calculated. This group would have to meet some more stringent rules to opt out of energy efficiency programs. However, because

those rules are not yet developed or known, it was conservatively assumed for the high case that all of them may be able to ultimately opt out.

Finally, several companies that were believed to be candidates to aggregate multiple accounts to the 2.5 MW level were identified. Because billing demand was not available for all of these accounts, an energy threshold was determined to represent a proxy for meeting the demand cut off. Customers that had energy consumption greater than 15.3 GWh were assumed to have a demand greater than 2.5 MW. This implies a 70% load factor, which is likely conservative for the types of customers under consideration. Customers included in these queries were ones that Ameren Missouri forecasting personnel were familiar with and in no way were meant to be an exhaustive list of all customers that could possibly opt out. Customers identified included hotel chains, retail chains, restaurant chains, and grocery chains.

Aggregating the three groups of customers that could potentially opt out, Ameren Missouri identified approximately 7 million MWh of annual usage as being potentially subject to the opt out provision. Estimated annual retail consumption of the C&I classes on a total basis (excluding Noranda) was approximately 19.5 million MWh (note that this estimate was prepared before the full load forecast was completed for the IRP and may not tie precisely to the base case forecast). Therefore, the percent of load eligible to opt out in the high case was determined to be approximately 35% (note the result was rounded down from 36% for simplicity). As mentioned above, because there is so little information about the likely behavior of eligible customers, the base case simply used the midpoint between the extreme scenarios as an estimate of the impact of this provision.

Table 7. 6: Maximum Opt-Out Potential

Customer Category	2009 MWh
>5 MW Individual (ex-Noranda)	4,202,589
>2.5 MW Individual	2,121,112
>2.5 Aggregate	703,316
Total	7,027,017

Table 7. 7: Opt-Out Scenarios

	High Case (All Eligible)	Base Case (Midpoint)	Low Case (Already Notified)
Total C&I Load Estimate (ex-Noranda)	19,479,367	19,479,367	19,479,367
Opt out MWh	7,027,017	3,952,103	877,190
Opt out %	36%	20%	5%

New Administrative Requirements

There are four new or revised rules from MEEIA that will affect future DSM efforts.

- 4 CSR 240-3.163 covering Electric Utility Demand-Side Investment Mechanisms. The second is
- 4 CSR 240-3.164 covering Electric Utility Demand-Side Programs Filing and Submission Requirements.
- 4 CSR 240-20.093 Demand-Side Programs Investment Mechanism.
- 4 CSR 24-20.094 Demand-Side Programs.

While these rules have not been approved at the time of its analysis, Ameren Missouri attempted to incorporate the potential impacts of new DSM rule requirements into its DSM modeling, program design, and implementation planning work as described below.

4 CSR 240-3.163 Electric Utility Demand-Side Investment Mechanisms

This rule set forth the information that an electric utility must provide when it seeks to establish, continue, modify, or discontinue a Demand-Side Programs Investment Mechanism (DSIM). This rule also sets forth the requirements for submission of information related to DSIM rate adjustment filings and for submission of annual reports as required for electric utilities that have a DSIM. Ameren Missouri attempted to consider incremental program administration costs required by the rule in the following areas:

- New annual reporting requirements
- Development and implementation of new models to estimate the impact of the DSIM on customers and utility earnings

- Development of models and systems to estimate of impacts of the DSIM on rates and customer bills for the 3-year implementation period
- Development of technical reference manuals – perhaps statewide

4 CSR 240-3.164 Electric Utility Demand-Side Programs Filing and Submission Requirements

This rule sets forth the information that an electric utility must provide when it seeks approval, modification, or discontinuance of demand-side programs. Ameren Missouri attempted to consider incremental program development, implementation and administrative costs required by the rule in the following area:

- Continually maintaining a current DSM market potential study based on primary data

4 CSR 240-20.093 Demand-Side Programs Investment Mechanism

This rule allows the establishment and operation of Demand-Side Programs Investment Mechanisms (DSIM), which allow periodic rate adjustments related to recovery of costs and utility incentives for investments in demand-side programs. Ameren Missouri attempted to consider incremental program administration costs required by the rule in the following areas:

- Development of accounting systems to track DSM related costs for compliance with the rule
- Development of systems to disclose DSIM costs on customers' bills
- The continuance of DSM tariff filings in addition to DSIM reporting requirements

4 CSR 24-20.094 Demand-Side Programs

This rule sets forth the definitions, requirements and procedures for filing and processing applications for approval, modification, and discontinuance of electric utility demand-side programs. This rule also sets forth requirements and procedures related to customer opt-out, tax credits, monitoring customer incentives and collaborative guidelines for demand-side programs. Ameren Missouri attempted to consider incremental program administration costs required by the rule in the following areas:

- Resources to address how to either achieve or not achieve annual demand-side savings targets or guidelines specified in the new rule that exceed maximum achievable potential identified in DSM potential studies

- Resources to address additional filing requirements when there is a variance of 20% or more in the approved DSM program annual budget
- Resources to address rule requirements for customers that choose to opt out of electric utility DSM programs
- Resources to determine eligibility to participate in DSM programs based on the customers' receiving a state tax credit
- Resources to administer statewide DSM advisory collaborative.

To account for these potential rule impacts, Ameren Missouri inserted a 1% (1% of total program costs) placeholder in the administrative costs for each program due to the uncertainty surrounding the specifics of the law and ambiguity around the final rulemaking during the inception of this plan. This planning assumption is thought to be a conservative estimate and yet is none-the-less a sizeable expense totaling more than \$1.5 million dollars over the three years.

7.2.3 Cost-Effectiveness Defined

Ameren Missouri calculated the cost effectiveness of its DSM measures, programs, and portfolios using the total resource cost ("TRC") test, the utility cost test ("UCT"), the participant cost test ("PCT"), and the ratepayer impact measure ("RIM") test.¹⁸ In each year of the planning horizon, the benefits of each demand-side program are calculated as the cumulative energy impact multiplied by all applicable avoided costs, and then summed into net present values for the timeframe considered.¹⁹ The definitions of the tests, drawing upon the California Standard Practice protocol for DSM economic assessment, are outlined below:

The Total Resource Cost (TRC) test measures benefits and costs from the perspective of the utility and society as a whole. The benefits are the net present value of the energy and capacity saved by the measures. The costs are the net present value of all costs to implement those measures. These costs include program administrative costs and full incremental costs (both utility and participant contributions), but no incentive payments to customers. The full incremental costs include single upfront costs and operational & maintenance costs where applicable.²⁰ Programs passing the TRC test (that is, having a B/C ratio greater than 1.0) result in a decrease in the total cost of energy services to all electric ratepayers.

¹⁸ 4 CSR 240-22.050(3)(G), 4 CSR 240-22.050(7)(C), 4 CSR 240-22.050(7)(D)

¹⁹ 4 CSR 240-22.050(7)(B), details for cost effectiveness screen are available in the Electronic Work Papers ("Measure Screen Data 11-18-2010.xlsx").

²⁰ 4 CSR 240-22.050(3)(C)

The Utility Cost Test (UCT) measures the costs and benefits from the perspective of the utility administering the program. As such, this test is characterized as the revenue requirement test. Benefits are the net present value of the avoided energy and capacity costs resulting from the implementation of the measures. Costs are the administrative, marketing and evaluation costs resulting from program implementation along with the costs of incentives. Programs passing the Utility Cost test result in overall net benefits to the utility, thus making the program worthwhile from a utility cost accounting perspective.

The Participant Cost Test (PCT) measures the benefits and costs from the perspective of program participants, or customers, as a whole. Benefits are the net present value savings that customers receive on their electric bills as a result of the implementation of the energy efficiency and demand response measures. Costs are the customer's up-front net capital costs to install the measures. If the customer receives some form of a rebate incentive, then those costs are considered as a credit to the customer and are subtracted from the customer's total capital costs.

The Ratepayer Impact Measure (RIM) test measures the difference between the change in total revenues paid to a utility and the change in total costs to a utility resulting from the energy efficiency and demand response programs. If a change in the revenues is larger or smaller than the change in total costs (revenue requirements), then the rate levels may have to change as a result of the program.

7.2.4 Avoided Costs

Table 7. 8 shows the avoided costs used for the valuation of Ameren Missouri's DSM efforts in the IRP analysis. A brief description of each component can be found below.²¹

Table 7. 8: Avoided Costs

Year	Energy (\$/MWh)	Capacity (\$/kW-Year)	Distribution (\$/kW-Year)	Transmission (\$/kW-Year)
2010	\$38	**HC**	\$19	\$9
2011	\$40	**HC**	\$20	\$9
2012	\$43	**HC**	\$20	\$9
2013	\$45	**HC**	\$21	\$10
2014	\$48	**HC**	\$22	\$10
2015	\$50	**HC**	\$22	\$10
2016	\$54	**HC**	\$23	\$11
2017	\$58	**HC**	\$24	\$11
2018	\$61	**HC**	\$24	\$11
2019	\$65	**HC**	\$25	\$11
2020	\$69	**HC**	\$26	\$12
2021	\$73	**HC**	\$27	\$12
2022	\$77	**HC**	\$27	\$13
2023	\$81	**HC**	\$28	\$13
2024	\$85	**HC**	\$29	\$13
2025	\$89	**HC**	\$30	\$14
2026	\$92	**HC**	\$31	\$14
2027	\$96	**HC**	\$32	\$15
2028	\$99	**HC**	\$33	\$15
2029	\$102	**HC**	\$34	\$15
2030	\$105	**HC**	\$35	\$16

Avoided Energy Costs

Because DSM measures produce savings for multiple years beyond the date of their installation, cost-effectiveness calculations require multiple years of economic forecasting. To estimate the avoided costs of electricity the Ameren Missouri Plan relied on energy market forecasts provided by CRA International's MRN-NEEM model projections.^{22,23}

CRA International performed an analysis for 10 distinct scenarios based on possible combinations of three critical factors: Carbon Policy, Natural Gas Prices, and Load Growth. Each of the 10 scenarios had an associated market price for electricity. The

²¹ 4 CSR 240-22.050(11)(D), 4 CSR 240-22.050(03)(B)

²² 4 CSR 240-22.050(02)

²³ 4 CSR 240-22.050(11)(D)

probability weighted average of the 10 scenarios was the data stream used for the relevant avoided energy costs in the Ameren Missouri DSM program analysis. Each avoided cost was levelized over the 20 year planning horizon.²⁴ Chapter 2 contains further detail on the development of electricity market price projections.

Avoided Capacity Costs

Highly Confidential

²⁴ 4 CSR 240-22.050(03)(B)1

Avoided Transmission and Distribution Costs

Avoided transmission and distribution (T&D) costs come from integrated system effects and are difficult to quantify, as opposed to energy and capacity costs where there are markets with specific prices. As part of integration modeling Ameren Missouri attributed the MW impacts of DSM programs with a corresponding reduction in capital expenditures associated with T&D expansion.

Avoided Distribution Cost

Ameren Missouri has estimated the marginal cost of system capacity by reviewing a variety of bulk substation and distribution substation projects to determine a generic marginal cost of distribution capacity expansion. Typical costs for distribution circuit construction and line transformers were included, as were allowances for service drops and sub-transmission line construction. The overall generic marginal cost of system capacity was valued at approximately \$400/kW.

In order to understand the relationship between the generic marginal cost of system capacity to load growth an analysis has been conducted to determine how much capacity has been or will be added to the system. However, the evaluation of the portion of distribution system build-out required to serve load growth is complicated by the fact that projects serve a variety of purposes; capacity upgrades to serve incremental system load, capacity upgrades to serve relocated system load, and refurbishment or replacement of equipment to avoid imminent failure.

The total expenditures on capacity projects for 2005 through 2014 are \$1.34 billion (\$134 million annually). Of that total \$411 million is for new business, \$392 million is for distribution line work and \$537 million is for bulk and distribution substations. The generic marginal cost of distribution capacity indicates how much total system capacity has been added but does not indicate the purpose of the capacity. However if we consider the amount of load growth we estimate from 2005 through 2014 it indicates approximately 10% of the expenditures are attributable to load growth.

Not all system expansion costs can be deferred through the efforts of demand-side resources. Distribution line work and substation projects may be reduced or delayed but new business expenditures will be unaffected. This indicates approximately \$9.6 million annual expenditures could be affected by demand-side resources. However, of the projects that are postponed or cancelled, some of the expenditures allocated to the new projects will need to be spent to refurbish or replace the associated existing equipment. It is assumed that 40% of the potential savings will be expended in this

manner and only 60% of the potential savings will actually be realized. After appropriate adjustments the estimated avoidable annual expenditures is \$5.8 million. Using a levelized fixed charge rate of 12.42% and an average annual growth of 38.4 MW, the avoided distribution cost is estimated to be \$18.60 kW-year in 2009 dollars.²⁶ The annual stream is a 3% escalation from that starting point and is available in

Avoided Transmission Cost

Avoided electric transmission costs began with a similar generic marginal cost of system transmission capacity, and have been estimated by applying the following factors:

- Usage growth-related factor - This factor captures the effect that some of the transmission projects may not be deferrable by DSM because they have not been driven by usage growth but rather by customers relocating to different areas. In these cases, there is local growth but not system wide growth.
- Location-specific Factor/Deferrable Factor - This factor accounts for the fact that Ameren analyzes the system as an aggregate and cannot tell whether load pockets will be deferred by DSM programs. Since DSM programs are not being designed to avoid or offset specific transmission projects, there is no certainty as to which projects will actually be deferred.
- Condition/Reliability Replacement Factor - This factor approximates the effect that load growth projects cause transmission asset turnover, so if Ameren Missouri does not upgrade or replace a substation because of DSM, then Ameren Missouri will need to spend money on additional maintenance or reliability projects that would have been avoided had new equipment been installed to meet load growth. For example, choosing 70% for this factor says that for every \$1 saved from DSM, \$0.30 is needed to support the equipment that would have been replaced with new equipment.

The explicit avoided cost values developed from the above transmission and distribution considerations are available in Table 7. 8.

Avoided Ancillary Service Cost

The ancillary services market in the Midwest ISO went live on January 6, 2009 as MISO Day 3. The ancillary service market is characterized by three services: regulation reserve, spinning reserve, and supplemental reserve.

²⁶ 4 CSR 240-22.050(3)(B)

- Regulation Reserve is unloaded and loaded capacity utilized by the Midwest ISO balancing authority to manage the area control error as necessary to comply with applicable reliability standards.
- Spinning Reserve is synchronized unloaded capacity set aside to be available to immediately offset abnormal supply deficiencies.
- Supplemental Reserve is unloaded capacity set aside to be available to offset abnormal supply deficiencies.

Since the Midwest ISO ancillary services market is relatively immature and the total ancillary services 2010 year-to-date through October cost is only 16 cents per megawatt hour, no estimate of avoided ancillary services has been included in Ameren Missouri's analysis at this time.

7.2.5 Overview of the EE Analysis

7.2.5.1 DSMore Model

Demand Side Management Option Risk Evaluator (DSMore™) is a powerful financial analysis tool designed to evaluate the costs, benefits, and risks of demand side management (DSM) programs and services. This tool, built by Integral Analytics, is the leading DSM cost-effectiveness model and is used in more than 27 states for DSM program planning. The power of DSMore lies in its ability to process millions of calculations resulting in thousands of cost effectiveness results that vary with weather and/or market prices.

DSMore provides all of the familiar cost effectiveness test results, including Utility Cost Test, Total Resource Cost Test, Ratepayer Impact Measure Test, and Societal Test. Moreover, these test results are provided for various weather conditions, including "normal" weather, and under a number of wholesale market conditions. DSM measures typically perform better during higher priced wholesale markets and more extreme weather. In fact, given that these two environmental forces tend to occur at the same time, the added boost in value that accrues to DSM avoided cost has a natural upward movement in value. By viewing numerous test results, the upward movement in DSM cost effectiveness becomes apparent.

Customization of the DSMore model by Integral Analytics and Ameren Missouri for measure analysis and program development included the addition of the following data specific to the Ameren Missouri service territory:

- Historic weather data

- Hourly market price data²⁷
- Historic rate level hourly energy usage (8760 load shapes)
- Rate information for the for the following classes
 - 1M RES Residential
 - 2M SGS Small General Service
 - 3M LGS Large General Service
 - 4M SPS Small Primary Service
 - 11M LPS Large Primary Service
- Annual avoided electric energy cost projections (summed over all avoided cost periods)²⁸
- Annual avoided capacity costs
- Avoided T&D costs
- Line loss factors applicable to the electric rates to perform calculations at transmission level
- Discount Rate
- Inflation Rate
- Hourly end-use load shapes (twenty year projections of 8760 load shapes) that represent the major end-usages of the customer population²⁹
 - All of the analyzed measures were assigned an end-use load shape
- Hourly system load shape (twenty year projection of 8760 hourly load shape with no energy efficiency programs present)

It should be noted that the DSMore model's energy inputs and outputs discussed in this report are at the MISO transmission level, and thus include the line loss factors necessary to aggregate and report impacts at that level.

7.2.5.2 Measure Level Screening

Ameren Missouri used multiple sources of data for the analysis of energy efficiency measures. The primary source of data was the Morgan Measure Library. Morgan Marketing Partners ("MMP") works with many DSMore users to develop utility specific databases of energy efficiency technologies and building simulations to use in program planning. Key features of the Morgan Measure Library include:

Two databases of residential and business measure level cost and savings data (weather sensitive and non-weather sensitive) that have been customized for the Ameren Missouri service territory. A full list of measures considered in the development of a menu of energy efficiency and energy management measures can be found in the

²⁷ 4 CSR 240-22.050(2)(B)

²⁸ 4 CSR 240-22.050(03)(B); 4 CSR 240-22.050(03)(B)2

²⁹ EO-2007-0409 – Stipulation and Agreement #30; EO-2007-0409 – Stipulation and Agreement #27

first column the spreadsheet labeled "Measure Screen Data 11-18-2010.xlsx"³⁰ found in the Electronic Work Papers.^{31 32} The column labeled "End Use Effectuated" categorizes each measure into end-uses such as lighting, refrigeration, heating, cooling, water heating, and motors.³³ The annual energy savings and coincident peak demand impacts per customer are located in the ninth and tenth columns respectively. The annual savings values were used for cost-effectiveness screening and the resulting TRC ratios for each measure in each customer class are shown in the last 5 columns of the spreadsheet.³⁴ The incremental costs per measure are also shown in the spreadsheet.³⁵

This database contains not only stand-alone efficiency measures, but also several bundled measure combinations.³⁶ For example, many of the HVAC systems were viewed on a holistic basis incorporating several measures including an efficient air conditioner, refrigerant charge correction, fan motors, duct sealing, etc. The Business programs' motors components incorporated a whole motor system integrating a system audit, motor incentives, and recommendations on process upgrades.

The following special considerations were accounted for in the Weather Sensitive measures:

- The weather basis used for analysis of weather sensitive measures consists of National Oceanic and Atmospheric Association ("NOAA") historic hourly weather data (precipitation, temperature, dew point, winds, visibility, cloud cover, pressure) recorded in St. Louis, MO.
- A set of residential, commercial and industrial prototypical building models were developed using the DOE-2.2 building energy simulation program (more than 2900 were developed) for each of the market segments defined within the Morgan Measure Library.³⁷ The prototypes are based on the models used in the California Database for Energy Efficiency Resources (DEER) study, with appropriate modifications to adapt these models to local design practices and climate.³⁸
- MMP provided a tool for blending the results of the discrete analyses and costing data to simplify further cost effectiveness analyses within the measure screen.

³⁰ EO-2007-0409 – Stipulation and Agreement #20.

³¹ 4 CSR 240-22.050(01)(A), 4 CSR 240-22.050(11)(A)

³² 4 CSR 240-22.050(01)(D)

³³ 4 CSR 240-22.050(01)(C), 4 CSR 240-22.050(01)(D)

³⁴ 4 CSR 240-22.050(03)(A), 4 CSR 240-22.050(11)(C)

³⁵ 4 CSR 240-22.050(11)(B)

³⁶ EO-2007-0409 – Stipulation and Agreement #26

³⁷ 4 CSR 240-22.050(06)(A), 4 CSR 240-22.050(11)(F)

³⁸ 4 CSR 240-22.050(05)

The third column of the table in "Measure Screen Data 11-18-2010.xlsx" labeled "Weath. Sensv." is populated with WS to denote a weather sensitive measure.³⁹

- Approximately 65 residential measures were analyzed for the possible combinations of the following residential building types, sizes, vintages, and applicable HVAC technologies – resulting in a total of approximately 2975 DOE 2.2 analyses.⁴⁰
- Approximately 160 commercial and industrial measures were analyzed for the possible combinations of the following commercial building types and applicable HVAC technologies – resulting in a total of more than 750 DOE 2.2 analyses.

Table 7. 9: Residential Weather-Sensitive Modeling Variables

3 vintages of single and multi-family building types	7 HVAC technologies within single and multi-family homes	2 sizes of multi-family residential buildings	3 vintages of manufactured home types	6 HVAC technologies within manufactured homes
Old, poorly insulated (1950s)	Central AC with gas furnace	2-4 unit buildings	Old (Pre 1978)	Central AC with electric furnace
Existing, average insulation (1950-2004)	Central air source heat pump	5+ unit buildings	Existing, average (1978-1994)	Central AC with gas furnace
New (2004+)	Central dual fuel heat pump		Newer (1995-2005)	Central air source heat pump
	Electric furnace no AC			Central dual fuel heat pump
	Gas furnace no AC			Electric furnace no AC
	PTAC			Gas furnace no AC
	PTHP			

³⁹ 4 CSR 240-22.050(03)(A)

⁴⁰ EO-2007-0409 – Stipulation and Agreement #26

Table 7. 10: Commercial & Industrial Weather-Sensitive Modeling Variables

13 Commercial and Industrial Building Types	9 HVAC technologies within select C&I Building Types
Assembly	Constant Volume ("CV") reheat economizer with Air Cooled Chiller
Big Box Retail	CV reheat economizer ("econ") with Gas Engine Chiller
Fast Food Restaurant	CV reheat econ with Water Cooled Chiller
Full Service Restaurant	CV reheat no econ with Air Cooled Chiller
Grocery	CV reheat no econ with Gas Engine Chiller
Hospital	CV reheat no econ with Water Cooled Chiller
Hotel	Variable Air Volume ("VAV") reheat econ with Air Cooled Chiller
Large Office	VAV reheat econ with Gas Engine Chiller
Light Industrial	VAV reheat econ with Water Cooled Chiller Assembly
Primary School	
Small Office	
Small Retail	
Warehouse	

The Non-Weather Sensitive Database from MMP consisted of measure level data for 200 commercial and 74 residential measures.⁴¹ The third column of the table in "Measure Screen Data 11-18-2010.xlsx" labeled "Weath. Sensv." is populated with "NWS" to denote a non-weather sensitive measure.⁴²

Ameren Missouri reviewed the detailed data and analyses contained within the entire Morgan Measure Library to assess its accuracy and completeness. The non-weather sensitive database was then refined using results from the Ameren Missouri DSM market potential study (described above and in the Electronic Work Papers "Studies Folder"), as well as other recognized energy efficiency databases. Ultimately this resulted in a final non-weather-sensitive database consisting of 236 commercial and 107 residential measures.⁴³

⁴¹ 4 CSR 240-22.050(01)(A)

⁴² 4 CSR 240-22.050(03)(A)

⁴³ 4 CSR 240-22.050(05), 4 CSR 240-22.050(11)(E)

The weather sensitive and non-weather-sensitive databases were combined and duplicate measures and nonsensical measures were removed using a qualitative screen. The final master measure database after all these steps consisted of 425 measures for analysis. This database contains a plethora of best-practice measures that are compliant with existing code, account for future code changes (as in residential and business lighting), are technologically advanced (solar thermal, LED lighting), and offer consumers multiple efficient options.⁴⁴ Furthermore, various categories of measures previously understudied were incorporated into the analysis including emerging technologies, bundled measures, and targeted measures.⁴⁵

Interactive Effects

Interactive effects were assessed by Ameren Missouri's contractors for both the Ameren Missouri DSM Potential Study and the DOE-2.2 modeling that was performed by MMP for measures within the Morgan Measure Library. Capturing the interactive effects of all applicable measures required examining many instances where multiple measures affect a single end use both positively and negatively. To avoid overestimation of total savings, the assessment of cumulative impacts accounts for the interaction among the various end uses.⁴⁶

Within the DOE-2.2 models, this was accomplished by establishing a base level model that incorporated many non-related measures and identifying the savings achieved by stacking the incremental measure within an additional modeling run, with a comparison of the base and modified runs to arrive at the implemented measure impact on energy consumption.⁴⁷

Checking Measure Level Results

Ameren Missouri went to great lengths to check the reasonableness of the Morgan Measure Library. Ameren Missouri performed a review of data provided by other data sources and contrasted that information with the data contained within the Morgan Measure Library to validate, or adjust if necessary, the measure database. The other measure databases that were used to validate the Morgan measure database contents were:

- Global Energy Partners measure database for DSM potential studies
- The Cadmus Group's measure database for DSM potential studies
- DEER 2008
- ICF 2008 data from Ameren Missouri's 2008 IRP Plan
- ENERGY STAR

⁴⁴ EO-2007-0409 – Stipulation and Agreement #24

⁴⁵ EO-2007-0409 – Stipulation and Agreement #28

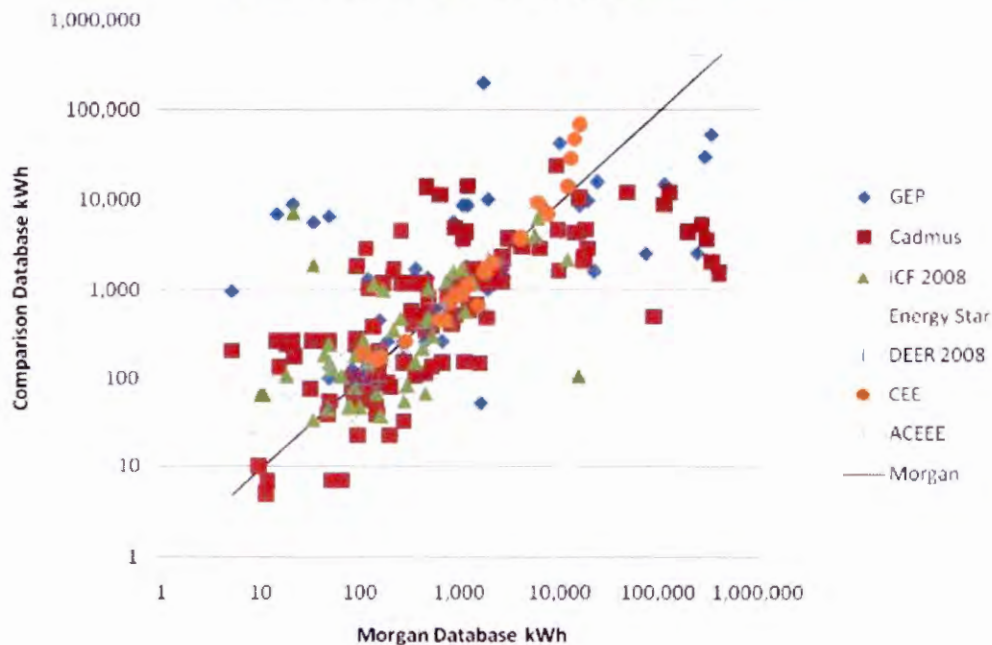
⁴⁶ EO-2007-0409 – Stipulation and Agreement #26

⁴⁷ 4 CSR 240-22.050(06)(B)

- American Council For An Energy Efficient Economy (“ACEEE”)
- Consortium For Energy Efficiency (“CEE”) ⁴⁸

The following graph illustrates just one of the validation processes that Ameren Missouri performed. This example shows a comparison of the incremental kWh savings value associated with the same energy efficiency measures from the various databases: Outliers, when present, were subsequently investigated, and corrective actions were implemented when necessary. As can be seen, the measure savings of the various sources trend as expected: along a diagonal line with a slope of one. This indicates that the sources feeding the measure database tend to converge.

Figure 7. 11: Measure kWh Scatter Plot



With the master measure database assembled, Ameren Missouri then conducted a measure level screen for each measure in all rate classes (1M-Res, 2M-SGS, 3M-LGS, 4M-SPS, and 11M-LPS).⁴⁹ This resulted in a total of more than 4000 measure level screening analyses being performed in DSMore to assess the cost-effectiveness using the TRC test.

To be inclusive of marginally cost-effective measures and provide greater diversity in the Ameren Missouri program mix, the measure level TRC criterion was set at 0.90. That is, individual measures tested without program costs were required to have a TRC

⁴⁸ EO-2007-0409 – Stipulation and Agreement #27

⁴⁹ 4 CSR 240-22.050(01)(A)

benefit-to-cost ratio greater than 0.90 in order to pass the measure screen. Table 7.11 illustrates the number of passing measures. Table 7.12 subsequently lists the passing measure categories that have been included in the planning horizon. (These categories may include an aggregation of more specific measures.)

The worksheet "Measure Screen Data 11-18-2010.xlsx" found in the Electronic Work Papers shows the results for each measure's TRC result for each applicable customer rate. All measures passing the screening test have been highlighted in green.⁵⁰

Table 7.11: Number of Measures Screened

	Measures Screened	Measures Passed	Percent of Measures Passed
Residential	152	80	53%
Business	273	171	63%
Total	425	251	59%

Table 7.12: Measure Categories Passing the TRC

Residential Measure Categories	Business Measure Categories
Air Source Heat Pump	Air Source Heat Pump
Basement Wall Insulation	Anti Sweat Heater Controls
Ceiling Fan	Barrel Wraps Inj Mold and Extruders
Central Air Conditioner	Central Air Conditioner
CFL bulbs – specialty	Ceramic metal halide lighting
CFL bulbs – standard	CFL bulbs – specialty
CFL fixture	CFL bulbs – standard
Crawlspace Wall Insulation	CFL fixture
Dehumidifier recycling	CHW reset
Dual Fuel Heat Pump	Commercial clothes washer
Duct Insulation	Commercial freezer – ENERGYSTAR
Duct Sealing	Commercial ice machine – ENERGYSTAR
ECM blower	Commercial refrigerator – ENERGYSTAR
Efficient faucet aerator	Compressed Air Optimization - Leak Audit, New Compressors, Improved Controls
Efficient pool pump	Cooking Equipment
Efficient showerhead	Cool roof
Electric Water Heater EF 0.93+	Daylight Sensor controls

⁵⁰ 4 CSR 240-22.050(03)(E); 4 CSR 240-22.050(11)(C)

Freezer recycling	Delamping
Geothermal heat pump	Demand Controlled Ventilation
Geothermal HP Desuperheater	ECM case motor
Gravity film heat exchanger (GFX)	Efficient Chiller
Heat Pump Clothes Dryer	Efficient Condenser
Heat Pump Water Heaters	Efficient faucet aerator
High Intensity Discharge Lamps (HID) - Exterior	Efficient motor
HVAC Maintenance and Tune-up	Efficient pool pump
Infiltration reduction	Efficient pump
LED lights	Efficient Refrigeration Condenser
Lighting Timeclock	Efficient showerhead
Metal Halide Outdoor Lighting	Energy Management System
Multiple Drawer Refrigerators	Engineered Nozzles Compressed Air
Occupancy Sensor	Exterior lighting control
Outdoor Lighting - Photovoltaics	Floating Head Pressure Control
Packaged Terminal Air Conditioner ("PTAC")	Geothermal heat pump
Packaged Terminal Heat Pump ("PTHP")	Guest Room Energy Management
Pipe Wrap	Head Pressure Control
Programmable / Set-back Thermostat	Heat Pump Water Heaters
Radiant Barrier	High bay T5 fluorescent lights
RCA improvement	High Intensity Discharge Lamps (HID) - Exterior
Refrigerator recycling	High performance T8 fluorescent lights
Room AC recycling	Infrared Heater
Smart power strip	LED Case lighting
Solar hot water heater	LED lights
Wall Insulation	Lighting Controls
Water heater blanket	Occupancy Sensor
Water heater thermostat setback	Optimizing Process Cooling
Window Air Conditioner	Optimizing Process Heating
	Pre rinse spray valve
	Programmable / Set-back Thermostat
	Pulse start metal halide lighting
	Radiant Barrier
	Refrigerant charging correction
	Refrigeration strip curtains
	Retrocommissioning, Lighting
	Smart power strip
	Timeclocks
	Tractor Heater Timers
	Vending Equipment Controller

	VFD air compressor
	VFD fan
	VFD motor
	VFD pump
	Wall Insulation
	Water loop heat pump
	Window replacement

7.2.5.3 Bundling Measures into Programs

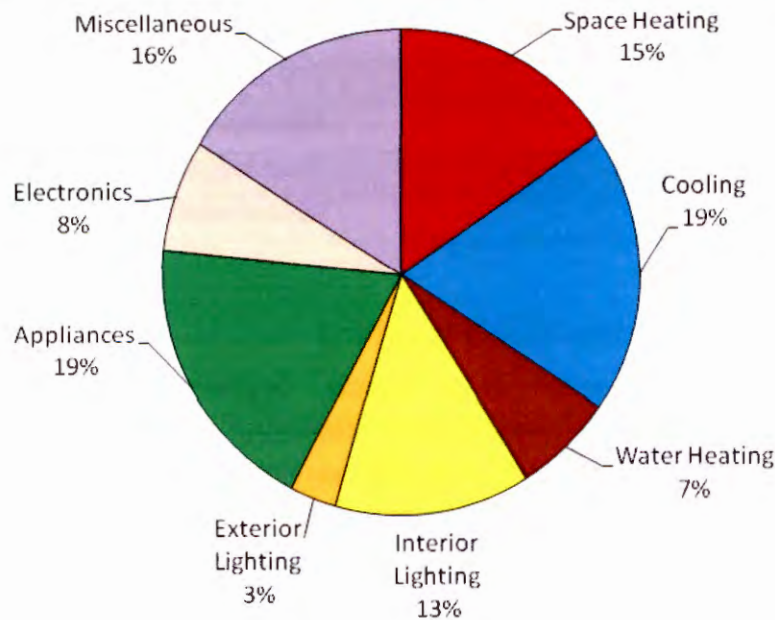
An energy efficiency measure is a device, appliance, or practice which, when implemented for a home, business, or manufacturing process, results in a reduction in the amount of energy used per unit of useful service. For program design purposes, all measures passing the screening analysis were considered and incorporated into at least one program, and in many cases, multiple programs.⁵¹ In general, related measures were grouped together for bundling into programs. Each program was comprised of a cross-cutting set of measures capable of cost-effectively addressing the characteristics of each market segment.⁵²

Program participation estimates for each measure in each year of the implementation plan were based on participation rate assumptions and measure allocations derived from the DSM potential study and mapping exercise outlined above in Section 7.2.1.4. The primary market research obtained from the 2009 Ameren Missouri DSM potential study was used to clarify and define the program components to achieve those savings.⁵³ As an example, the following pie chart from the potential study describes how energy is used at the end-use level by Ameren Missouri Residential customers:

⁵¹ 4 CSR 240-22.050(3)(F)

⁵² 4 CSR 240-22.050(06)(C)

⁵³ 4 CSR 240-22.050(05)

Figure 7. 12: Base Year Residential Electric Consumption by End Use

Once participation levels were identified and incorporated, program design work could begin. Ameren Missouri incorporated multiple components in the program design phase including primary market data from the Potential Study and also input from its implementation team. An example of how information from the Potential Study was used in the program design process, consider residential space heating – both electric and gas. The market share and equipment saturation of electric space heating in the Ameren Missouri market is relatively low, but because of the high energy intensity of this end use, the electric energy consumed in space heating (15%) is nearly equivalent to the electric energy used for cooling (19%), where the Ameren Missouri market share and equipment saturation is almost 100%. This speaks to the need for exploration of a program focused around improving electric space heating efficiency through various measures including furnace fan upgrades.

Input from the Ameren Missouri DSM implementation team was also a significant factor in the program design process. The implementation team has gained significant experience from participation in the energy efficiency market at both the residential and business levels. They have firsthand field experience and identified the necessary program elements required to move the market. Estimation of incentive levels, program administration and marketing costs, and portfolio level costs were based primarily on the Ameren Missouri implementation team's experience during Cycle 1.

The combination of all energy efficiency programs, both business and residential, comprises the energy efficiency portfolio. This report and its appendices primarily

represent one particular portfolio, although there were several other portfolios developed for various alternative resource plans. The full array of portfolios developed is discussed in Section 7.8.⁵⁴

7.2.5.4 Program Cost-Effectiveness Screening

Once measures had been assembled into programs, each program was analyzed using the aforementioned cost-effectiveness metrics, primarily the TRC test.⁵⁵ The program screening process added program-level and portfolio-level costs to the bundled measures to estimate the level of their total delivered cost. The method in which these costs were developed has been described below. All programs that were included in the residential and business portfolios were designed to have a TRC ratio greater than 1.0, with the exception of the Low Income program. This is because typical Low Income programs target a hard-to-reach market and it is common practice for the utility to offer fully installed measures in this program with little or no cost to the customer.⁵⁶

Accompanying the TRC calculations are several other cost-effectiveness tests. For each program, TRC, RIM, and UCT tests also were calculated.⁵⁷ The cost-effectiveness results were more accurate than the 2008 IRP filing by utilizing more granular hourly data and the newly acquired modeling tool DSMore.⁵⁸ These results, along with participation estimates, program costs, utility costs and energy and demand reduction estimates (load impacts) are in the electronic appendices for each given portfolio (i.e. Low Risk, RAP, etc.) within each program BatchTool ('Portfolio Screens' folder and then select desired portfolio and program).⁵⁹

Calculation of Incentive Costs

Incremental costs which include upfront costs and operational & maintenance costs are listed in the "Measure Screen Data 11-18-2010.xlsx".⁶⁰ Incentive costs were calculated by summing the average, per-measure incentive levels that were developed according to the following methodology.

1. First, a simple payback analysis was performed on each measure to arrive at the initial target incentive level. This determined the incentive amount required to supplement the customer's electric bill savings such that the incremental cost of the measure would be paid back in 2 years.
2. Second, upper and lower constraints were applied for each program based on an appropriate percent of incremental cost. These constraints were established

⁵⁴ 4 CSR 240-22.050(07)(F)

⁵⁵ 4 CSR 240-22.050(07)

⁵⁶ 4 CSR 240-22.050(07)(E)

⁵⁷ 4 CSR 240-22.050(07)(C)

⁵⁸ EO-2007-0409 – Stipulation and Agreement #30

⁵⁹ 4 CSR 240-22.050(07)(A), 4 CSR 240-22.050(11)(H)

⁶⁰ 4 CSR 240-22.050(03)(C)1-3

based on results from the Ameren Missouri Energy Efficiency implementation teams, the Ameren Missouri potential study efforts, and information from the last 3- year plan. These incentive thresholds are shown in the table below:

Table 7. 13: Incentive Thresholds by Program (% of Incremental Cost)

ENERGY EFFICIENCY PROGRAM	Max Limit (%)	Min Limit (%)
RES-Lighting	30%	20%
RES-HVAC	30%	20%
RES-Appliance Recycling	N/A	N/A
RES-Low Income	100%	100%
BUS-Standard	30%	20%
BUS-Custom	Based on \$/ first year-kWh saved	
BUS-RCx	35%	20%
BUS-New Construction	40%	20%
BUS-Multifamily Common	30%	20%

- Finally, the resulting incentive level was reviewed and, in some cases, manually adjusted based on information from actual field experience, other utilities' program experience, the EM&V contractor teams, and market conditions.

An example of a manually adjusted incentive is the ground source heat pump ("GSHP"). Steps 1 and 2 above for the Energy Efficient Products Program would have set the incentive level between 20% - 30% of incremental cost. A comparison of the broader market and other utility incentive levels, however, caused Ameren Missouri to reduce its GSHP incentive in PY4 to \$800, or approximately 10% of the incremental measure cost. This more accurately reflects market conditions.

Another exception to the above methodology is when an assessment of market needs dictates that full measure cost or direct installation of measures must occur. This is the case in programs such as Low Income.

Specific incentive levels are available in the program templates and appropriate program BatchTools.

Calculation of Administrative Costs

Portfolio Administrative Costs were calculated on a per-measure basis. These administrative costs were determined as a percentage of incentive costs and applied with a logarithmic decline over the duration of the program. This logarithmic decline is

assumes that administrative costs should decline over time due to lessons-learned, increased operational efficiencies, and economies of scale.

Portfolio Level Cost Estimates

There are 4 Portfolio Level Costs applied on a per-program basis: Portfolio Administrative Costs, EM&V Costs, Educational Costs, and Marketing Costs. Each cost was calculated by applying the following percentages to the Total Program Costs:

Table 7. 14: Portfolio Level Costs*

Portfolio Admin Costs	6.0%
EM&V Costs	5.0%
Educational Costs	2.5%
Marketing Costs	2.5%

**Total Program Costs include the Program Administrative Costs (previously mentioned), Incentive Costs (previously mentioned), Implementation Costs, and any Miscellaneous Costs.*

Portfolio administrative costs include a 1.0% of total program costs increase comply with new rules from MEEIA, as described in Section 7.2.2 above.

7.2.5.5 Net-To-Gross (“NTG”) Assumptions

Program cost-effectiveness is based on program net savings – savings that are attributable directly to a program after netting out non-program effects. Net savings are accounted for in the calculation by multiplying gross program savings by what is known as the net-to-gross ratio. The net-to-gross (“NTG”) ratio is the ratio of the verified net savings for a program to the verified gross savings. Ameren Missouri sought to encompass the following three factors in the NTG ratio, which the industry commonly recognizes as the primary drivers in the difference between net and gross savings:

- (1) Free Ridership – defined as the portion of customers who would have implemented an efficiency measure even in the absence of a program incenting it.
- (2) Free Drivership, or Spillover – defined as the portion of customers who adopt a measure that has been promoted by a program after having been influenced by the program, but without taking the program incentive.
- (3) Realization Rate – defined as the rate by which actual energy savings reflect estimated energy savings. Various factors affecting this metric include the installation rate of a group of measures, portion of those measures that are actually correctly installed, and actual hours of operation and actual measure quantity and type can impact this rate

Although all effects should ultimately be accounted for in the calculation of net savings, evaluations have often ignored the spillover effect. The effect of applying the NTG ratio, therefore, is to reduce program savings and cost-effectiveness.

For Cycle 2 program planning purposes, Ameren Missouri based individual program NTG assumptions on Cycle 1 EM&V results, Ameren Illinois EM&V results, and previous planning work where applicable. Table 7. 15 shows the NTG assumptions for the Ameren Missouri portfolio of proposed Cycle 2 programs:

Table 7. 15: NTG Planning Assumptions

Program	Net to Gross Factor	Notes
RES-Lighting	0.80	Deemed reasonable by EM&V.
RES-HVAC	0.80	Not yet evaluated. Considered best practice.
RES-Appliance Recycling	0.54	Based on EM&V calculated data in Ameren Illinois program.
RES-Low Income	1.00	Subsidized incentives allow targeting of segment who would not otherwise act on EE.
BUS-Standard	0.80	Deemed reasonable by EM&V.
BUS-Custom	0.80	Deemed reasonable by EM&V.
BUS-RCx	0.80	Deemed reasonable by EM&V.
BUS-New Construction	0.80	Deemed reasonable by EM&V.
BUS-Multifamily Common	0.80	Deemed reasonable by EM&V.

7.2.5.6 Hourly Load Shapes

Creating Unitized Measure Level End-Use Load Shapes

As mentioned in Section 7.2.5.6, a set of hourly forecast end-use shapes were developed to represent all of the shapes of the measures that were being analyzed. These load shape forecasts were calendar aligned to be consistent with the hourly load forecast that was also mentioned in Section 7.2.5.6. These hourly shapes consisted of 8760 hours of load values for a 365 day year, and 8784 hours of load values for a 366 day year within the load forecast.⁶¹

To provide for scaling of the shapes to represent the savings that were projected by the modeling within DSMore, each year of each end-use shape was unitized on an annual energy basis,

⁶¹ 4 CSR 240-22.050(8)